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BEFORE THE ARIZONA CORPORATION COMMISSION 2016 JUN -3 P 4: 27

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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322 **NOTICE OF FILING REDACTED DIRECT TESTIMONY (REVENUE REQUIREMENT) AND EXHIBITS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT MINERALS CORPORATION, ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Freeport Minerals Corporation, Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submit the Redacted Direct Testimony (Revenue Requirement) and Exhibits of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

For the parties who have signed the Tucson Electric Power Company ("TEP") Protective Agreement, they will be able to view the confidential portion of Mr. Higgins' Testimony by accessing the TEP Rate Case Data Room site.

RESPECTFULLY SUBMITTED this 3rd day of June, 2016.

FENNEMORE CRAIG, P.C.

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

REDACTED

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation and

Arizonans for Electric Choice & Competition

Revenue Requirement

June 3, 2016

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My revenue requirement testimony is being sponsored by Freeport Minerals Corporation and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

[1] Henceforth in this testimony, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in approximately twenty proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on APS 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.

Decision No. 62103 (2007),[14] the TEP 2007 rate case (2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] the TEP 2011 Energy Efficiency Plan (2012),[18] the TEP 2012 rate case (2012),[19] the APS Four Corners Rate Rider proceeding (2014),[20] and the UNSE Electric, Inc. ("UNSE") 2015 rate case (2015).[21]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 180 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.
[17] Docket No. E-01345A-11-0224.
[18] Docket No. E-01933A-11-0055.
[19] Docket No. E-01933A-12-0291.
[20] Docket No. E-01345A-11-0224.
[21] Docket No. E-04204A-15-0142.

<u>OVERVIEW AND CONCLUSIONS</u>

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses three major topics concerning revenue requirement:

(1) TEP's request for a non-fuel rate increase of $109.5 million;

(2) Certain revenue requirement issues pertaining to the Purchased Power and Fuel Adjustment Charge ("PPFAC"); and

(3) TEP's proposed modifications to the Environmental Compliance Adjustment ("ECA").

In my testimony, I recommend adjustments to TEP's proposals that I believe are necessary to ensure rates that are just and reasonable.

I will address the topics of class cost-of-service, revenue allocation, buy-through service, and the Lost Fixed Cost Recovery mechanism in my Rate Design testimony.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that TEP's revenue requirement be reduced by **$48.587** million relative to the $109.5 million base rate increase proposed by the Company in its Application. My recommended adjustments are itemized in Table KCH-1, presented later in my testimony. My recommended reduction does not take into account or incorporate any other adjustments that may be offered by other parties which were not addressed in my testimony.

(2) The current PPFAC is structured to flow-through 100% of all deviations in fuel and purchased power costs to customers. This type of 100%

cost pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if it remained exposed to the energy cost risk. In my opinion, a risk-sharing mechanism is essential to keep customer and Company interests aligned. Consequently, I recommend adoption of a 70/30 risk-sharing mechanism in the PPFAC.

(3) The PPFAC Plan of Administration was changed in the last general rate case to shift the profits realized from new long-term contracts to the benefit of TEP shareholders instead of customers. This change should be reversed going forward. Instead, all revenues from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC, unless such sales are allocated a share of system costs.

(4) The ECA is an example of unwarranted single-issue ratemaking, but was included in the Settlement Agreement package negotiated by the parties to the last general rate case, subject to a cap of 0.25% of TEP's total retail revenue. In this case, TEP is proposing to double the ECA cap. I recommend that this change be rejected. Instead, I recommend that the Commission terminate the ECA, unless it is capped at the previously-negotiated 0.25% of TEP's total retail revenue.

ADJUSTMENTS TO PROPOSED BASE REVENUE INCREASE

Q. What increase in base revenues is TEP recommending in this case?

A. In its Application, TEP is requesting a non-fuel rate increase of $109.5 million, or 12.0% over total adjusted test year revenues, to become effective no later than January 1, 2017.[22] As noted in TEP's filing, based on the PPFAC that went into effect April 2015, TEP's proposal represents a net increase of $67.3 million, or 7.1% over total adjusted test year revenues including the higher fuel component.[23] However, the current PPFAC rate effective May 1, 2016 of $0.001501 per kWh is significantly less than the April 2015 rate of $0.00682 per kWh included in TEP's analysis. Consequently, the proposed net increase relative to *present* rates is greater than the 7.1% measured by TEP using the previous PPFAC rate.

Q. Do you have any recommended adjustments to TEP's proposed base rate increase?

A. Yes. I am recommending an overall reduction of **$48.587** million to TEP's proposed base rate increase relative to the Company's Application. This recommendation is presented in Exhibit KCH-1 and is summarized in Table KCH-1 and consists of the following adjustments, each of which will be discussed in turn:

[22] Application, p. 1.
[23] Direct Testimony of Dallas J. Dukes, pp. 32-33.

Table KCH-1
Summary of AECC Adjustments to TEP Revenue Requirements

	ACC Jurisdictional Adjustment Amount (\$000s)
Rate Base Adjustments	
Bonus Tax Depreciation Extension	(\$1,525)
Sundt & San Juan 2 M&S Regulatory Asset Adjustment	(\$43)
50.5% Co-Ownership of SGS 1 Regulatory Asset Adjustment	(\$4,673)
SGS 1 2006 Lease Acquisition Rate Base Adjustment	(\$1,488)
Capitalized Legal Cost Adjustment	(\$88)
Expense Adjustments	
Legal Expense Adjustment	(\$1,343)
Payroll Expense Adjustment	(\$1,222)
Short-Term Incentive Compensation Adjustment	(\$1,972)
Long-Term Incentive Compensation Adjustment	(\$1,296)
SERP Recovery Adjustment	(\$950)
Severance Costs Adjustment	(\$218)
Credit Card Processing Fees Adjustment	(\$3,482)
Generation Overhaul Adjustment	(\$1,865)
ROE Adjustment	
Return on Equity Adjustment	(\$10,826)
Jurisdictional Allocation Adjustment	
Demand Allocation Factor	(\$14,043)
Other Cost of Capital Adjustment	
Allowed Return on New TEP Headquarters Building Adj.	(\$3,552)
Total AECC Adjustments	(\$48,587)

Bonus Tax Depreciation

Q. What is bonus tax depreciation?

A. Bonus tax depreciation refers to a greatly accelerated tax deduction for depreciation that has been permitted pursuant to several statutes signed into law in recent years to stimulate the economy. Bonus tax depreciation was permitted in the early 2000s and reintroduced in 2008 and 2009 pursuant to the Economic

Stimulus Act of 2008, and the American Recovery and Reinvestment Act of 2009. It has since been extended several times but was scheduled to end on December 31, 2014, except under certain circumstances for qualified property placed in service through December 31, 2015.

Q. Has bonus tax depreciation been extended beyond December 31, 2014?

A. Yes. The Protecting Americans from Tax Hikes Act of 2015, part of H.R. 2029, was signed into law on December 18, 2015. This Act extends 50 percent bonus tax depreciation through December 31, 2017, and includes a phase down to 40 percent bonus tax depreciation in 2018, and 30 percent in 2019.

Q. How does bonus tax depreciation impact ratemaking for regulated utilities?

A. Bonus tax depreciation is a form of accelerated tax depreciation. Regulatory authorities, including this Commission, have long recognized that utility depreciation for tax purposes differs from utility book depreciation used in ratemaking. The timing difference between tax depreciation and book depreciation is recognized through the recording of accumulated deferred income tax ("ADIT"). Generally, the tax benefits of accelerated depreciation are not passed through *directly* to ratepayers, but rather certain indirect benefits are recognized through the determination of rate base. According to the conventions of income tax normalization, the benefit of a utility's ADIT is viewed as a source of zero-cost capital to the utility as part of the ratemaking process. Consequently, the ADIT that results from accelerated tax depreciation is booked as a credit against rate base, thereby reducing revenue requirements for customers.

Even though bonus tax depreciation affects rates through the same mechanics as standard accelerated depreciation, its impact is more dramatic than standard accelerated depreciation in the years immediately following the placement of the qualifying plant into service. This is because bonus tax depreciation causes a much greater increase in ADIT, which in turn, produces a much greater credit against rate base for any given amount of new plant in service. This, in turn, reduces the revenue requirement relative to what it would have been if bonus tax depreciation were not applicable.

Q. Why is the extension of bonus tax depreciation relevant for this proceeding?

A. Bonus tax depreciation has a material impact on utility revenue requirements. TEP's rate case was filed under the assumption that bonus tax depreciation would not be available past December 31, 2014. Since it is now known that bonus tax depreciation has been extended, it is necessary to properly reflect the ratemaking impact of this tax change.

Q. Has TEP provided information regarding the revenue requirement impact of extending bonus tax depreciation?

A. Yes. Based on TEP's response to discovery, the extension of bonus tax depreciation would result in a net increase in the magnitude of Total Company ADIT, or reduction to rate base, of approximately $15.9 million relative to TEP's filed case.[24]

Q. What is your recommendation to the Commission regarding the treatment of bonus tax depreciation on TEP's revenue requirement?

A. TEP's revenue requirement should be adjusted to reflect the impact of the extension of bonus tax depreciation.

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[24] TEP's Supplemental Response to AECC Data Request 1.3, Attachment AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes.xlsm, provided in Exhibit KCH-18. See also Exhibit KCH-2, page 2 of 2.

Q. What is the impact on TEP's jurisdictional revenue requirement from your adjustment?

A. My adjustment to reflect the extension of bonus tax depreciation is shown in Exhibit KCH-2. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.525** million.

Sundt and San Juan Unit 2 Materials & Supplies

Q. What is TEP proposing regarding Sundt coal handling facilities ("CHF") and San Juan Unit 2 materials and supplies?

A. According to the Direct Testimony of Frank P. Marino, the Sundt CHF are no longer expected to be used and useful as of April 2016, and closure of San Juan Unit 2 is expected by December 2017.[25] TEP is proposing to record the remaining materials and supplies inventory for the Sundt CHF and San Juan Unit 2 as a regulatory asset, and to amortize the cost over a three year period.[26]

Q. Do you agree with TEP's proposed treatment of the Sundt CHF and San Juan Unit 2 materials and supplies inventory?

A. Not entirely. TEP includes the entire inventory of $1.2 million in rate base, while also including approximately $400,000 in amortization expense based on the three-year amortization period. TEP does not reflect the impact of accumulated amortization as an offset against the inventory rate base balance.[27]

Q. What do you recommend regarding the ratemaking treatment of Sundt CHF and San Juan 2 materials and supplies?

[25] Direct Testimony of Frank P. Marino, pp. 9-10.
[26] *Id.*, p. 14, lns. 3-13.
[27] TEP's Rate Base - Sundt _ San Juan M_S adjustment workpaper; TEP's Income - Sundt _ San Juan M_S adjustment workpaper.

A. I recommend that the first year of amortization expense of approximately $400,000 be recorded as accumulated amortization, reducing the net rate base balance by the same amount. As TEP explains, the proposed three-year amortization period starts in the Test Year,[28] and TEP has included the annual amortization expense in its revenue requirement. Therefore it is appropriate to reflect the Sundt CHF and San Juan 2 materials and supplies net rate base after one year of accumulated amortization has accrued.

Q. What is the impact on TEP's jurisdictional revenue requirement from your adjustment?

A. My adjustment is shown in Exhibit KCH-3. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.043** million.

50.5% Co-Ownership of Springerville Unit 1

Q. What revenue requirement issues are you addressing regarding the 50.5% co-ownership of Springerville Unit 1?

A. At the time of TEP's Application, Springerville Unit 1 was co-owned by a third party, Alterna Springerville LLC ("Alterna"), with whom TEP had been engaged in extensive litigation. In the Company's Application and direct testimony, TEP makes a number of proposals regarding the ratemaking treatment of cost items associated with the 50.5% ownership share – proposals with which I have objections based on the circumstances existing at the time of TEP's filing. However, based on press reports published subsequent to the filing of TEP's Application in this case, it is my understanding that TEP has resolved its

[28] Direct Testimony of Frank P. Marino, p. 14, lns. 5-7, p. 42, lns 13-16.

differences with Alterna and intends to purchase Alterna's 50.5% interest. In light of these changed circumstances, TEP's proposals regarding the regulatory treatment of the costs associated with Alterna's 50.5% interest are no longer applicable. Consequently, I will not present my initial objections to these proposals. Rather, I am recommending that the special ratemaking provisions proposed by TEP to address the 50.5% co-ownership of Springerville Unit 1 be rejected because they are no longer applicable to the facts of this case. In addition, I address the legal expenses incurred by TEP in its dispute with Alterna as a separate issue in my testimony.

Q. What specific revenue requirement adjustments must be made to remove the special ratemaking provisions proposed by TEP regarding the 50.5% co-ownership of Springerville Unit 1?

A. I am aware of two distinct ratemaking treatments that TEP has proposed in this case with respect to the 50.5% co-ownership share of Springerville Unit 1. The first is the establishment of a regulatory asset in the amount of $23.9 million associated with facility improvements on the 50.5% co-ownership share.[29] The second is the inclusion of $16.291 million in non-fuel O&M expenses in the PPFAC, which would be potentially offset by wholesale margins from dispatch of the 50.5% co-ownership share of the plant.[30]

With respect to the first treatment proposed by TEP, I recommend that the requested regulatory asset should not be recognized by the Commission and the earnings on this asset and amortization expense be removed from the revenue

[29] See TEP Response to AECC Data Request 16.1, provided in Exhibit KCH-18.
[30] Direct testimony of Michael E. Sheehan, pp. 45-46.

requirement. I present this adjustment in Exhibit KCH-4. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$4.673** million.

With respect to the second treatment proposed by TEP, I recommend that the requested inclusion in the PPFAC of $16.291 million in non-fuel O&M expenses associated with the 50.5% ownership share of Springerville Unit 1 be rejected.

Q. In recommending that the Commission reject these special ratemaking proposals, are you substituting other revenue requirement adjustments to reflect TEP's acquisition of the 50.5% co-ownership share of Springerville Unit 1?

A. No. The burden for making the case and demonstrating the reasonableness of its acquisition of the 50.5% co-ownership share of Springerville Unit 1 rests with TEP. The Company has not put forward a revenue requirement proposal reflecting the acquisition of the 50.5% co-ownership share of Springerville Unit 1 at this time.

Springerville Unit 1 2006 Acquisition

Q. Please provide some basic background regarding TEP's 2006 Springerville Unit 1 lease equity purchase.

A. As explained in the direct testimony of witness Kentton Grant, in 2006 TEP purchased a lease equity covering 14.1% undivided interest in Springerville Unit 1 for $48.03 million. The lease was amended to eliminate the equity portion of rent payments. According to Mr. Grant, TEP continued making rent payments to cover the principal and interest payments on lease obligation bonds. In January 2015, TEP took direct ownership of the 14.1% undivided interest when the bonds were paid in full.

Q. Is TEP proposing an adjustment in this case related to its 14.1% ownership interest?

A. Yes. TEP is proposing to include the original $48.03 million acquisition cost in rate base, with a reduction of $5.31 million to reflect previous rent reduction benefits covering 2007 and 2008 that have been retained by TEP. Thus, TEP's net requested rate base is $42.72 million.

Q. What adjustment has TEP made in this case to reflect this $42.72 million in rate base?

A. Since purchasing the 14.1% lease equity in 2006, TEP has been amortizing its purchase in its accounting records. As of December 31, 2014, TEP's remaining unamortized amount was $36.06 million when the $5.31 million rent benefits credit is included. The associated accumulated amortization as of this date was $6.65 million. In addition, to reflect the proper test year period, TEP includes $0.07 million for six months of additional accumulated depreciation to reflect the unamortized balance as of June 30, 2015. TEP's total adjustment reflects the sum of these two amounts, $6.65 million and $0.7 million, for a total adjustment of $6.73 million to obtain the net Total Company requested rate base of $42.72 million.

Q. Do you agree with TEP's proposed test year amount for its 14.1% lease equity interest?

A. No. TEP's requested amount does not constitute a reasonable ratemaking treatment. As an initial matter, TEP's request to introduce into rate base today an acquisition that was made in 2006 is highly unusual. Second, the requested valuation of this acquisition for rate base purposes in an amount that is very close to the purchase price ten years ago strikes me as questionable on its face, given that the asset has been depreciating. Third, this situation is further convoluted by the applicable lease provisions during the interim period, during which time customers have paid for use of this asset in TEP's revenue requirement. Finally, the requested rate base amount of $42.72 million for the 2006 purchase exceeds the net book value of this asset, which on June 30, 2015 was only $26.53 million.[31]

Q. In your opinion, what is the proper rate base amount to include for TEP's 2006 lease equity purchase?

A. In light of the considerations I noted above, it does not strike me as reasonable to include in rate base an amount in excess of this asset's net book value. Therefore, I recommend using the net book value of the asset as of June 30, 2015 to value the rate base addition associated with the 2006 acquisition. Based on the net book value of the total SGS 1 unit, this amount is $26.53 million. Therefore, I am recommending a $16.26 million (total company) adjustment. As shown in Exhibit KCH-5, this adjustment reduces TEP's revenue requirement by approximately **$1.488** million.

[31] TEP's Response to AECC Data Request 11.3, provided in Exhibit KCH-18. To derive the $26.53 million the total plant net book value as of June 30, 2015 provided in the data response was multiplied by 14.1%, the 2006 lease equity purchase percentage.

Legal Costs

Q. What are your concerns regarding the amount of legal costs included in TEP's proposed revenue requirement?

A. I have concerns regarding the amount of legal costs included in TEP's requested revenue requirement both with respect to legal expense and rate base.

Q. What are your concerns regarding the inclusion of legal *expense* in TEP's proposed revenue requirement?

A. The test period includes an exceptionally high level of legal expense. As shown in Exhibit KCH-7, page 3, the adjusted test period legal expense of $3.256 million is well in excess of $1.776 million average for the three-year period 2011 through 2013, prior to the test period. It appears that much of this increase is attributable to litigation between TEP and the 50.5% owner of Springerville Unit 1, Alterna.

Q. How should the extraordinary level of legal expense associated with the Springerville Unit 1 litigation be treated for ratemaking purposes?

A. The extraordinary level of legal expense associated with the Springerville Unit 1 litigation should be removed from the retail revenue requirement. There are two reasons for this. First, the nature of the litigation concerned a dispute between power plant owners. Retail customers should not be responsible for underwriting TEP's legal costs in such a dispute, which lies outside the purview of providing retail service. In this proceeding, TEP has gone to considerable lengths to differentiate between its ACC-jurisdictional activities and business activities that TEP does not consider to be ACC jurisdictional, such as the profits that TEP makes from providing services to the owners of Springerville Units 3 and 4. TEP's revenue requirement proposal insulates the majority of those profits from being shared with customers and used to offset a portion of the increase in retail revenue requirement the Company is requesting.[32] The same reasoning applies here, except that in this instance, TEP is incurring *costs* that are outside the purview of retail service. Consequently, it is not appropriate to include these costs in the retail revenue requirement.

The second reason for excluding these costs from recovery is their exceptional nature. The adjusted test year legal expenses exceed the average of the three-year period 2011 through 2013 by $1.480 million, largely due to Springerville Unit 1 litigation expense. As such, the Springerville Unit 1 litigation expense should not be considered to be representative of ongoing legal expenses and should be adjusted out of the retail revenue requirement on those grounds alone.

Q. What is your recommendation to the Commission regarding legal expense?

A. I recommend that the extraordinary level of legal expense associated with the Springerville Unit 1 litigation should be removed from the retail revenue requirement.

Q. What is your concern regarding legal costs that TEP proposes to include in *rate base*?

A. TEP is proposing to include $919,042 of legal costs associated with its Alterna litigation in rate base as part of the acquisition cost of Springerville Unit

[32] See direct testimony of Dallas J. Dukes, p. 50. TEP's Income – Springerville Units 3 and 4 workpaper shows $28.5 million in net income from services provided to Springerville Units 3 and 4, $8.3 million of which is credited to customers and $20.2 million of which is retained by TEP.

1.[33] Just as I argued above with respect to legal expense, the cost of litigating the disputes between TEP and Alterna should not be shouldered by customers, as the disputes between these two facility owners are outside the purview of providing retail service. Therefore, these costs should not be included in rate base. As I noted above, TEP is careful to differentiate business activities that the Company does not consider to be ACC-jurisdictional when the benefits accrue to the Company. The same principle should apply to costs.

Q. What is your recommendation to the Commission regarding the inclusion of legal costs in rate base?

A. I recommend that TEP's proposal to include in rate base certain legal costs associated with the Springerville Unit 1 litigation between TEP and Alterna should be rejected.

Q. What is the impact on TEP's jurisdictional revenue requirement from your recommendations regarding legal costs?

A. My adjustment to rate base is presented in Exhibit KCH-6. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.088** million relative to TEP's filed case.

My adjustment to legal expense is presented in Exhibit KCH-7. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.343** million relative to TEP's filed case.

[33] Direct testimony of Kentton C. Grant, p. 33. Also, TEP Response to AECC Data Request 10.2.a.iv (provided in Confidential Exhibit KCH-19) as further clarified by TEP.

Payroll Expense

Q. What is TEP proposing regarding payroll expense?

A. Payroll expense is discussed in the Direct Testimony of TEP witness Frank P. Marino. Mr. Marino explains that TEP's Payroll Expense Adjustment was computed based on the average of O&M wages for the 12 month periods ended June 30, 2015 and June 30, 2014.[34] Using the average O&M wages for these two periods, TEP calculates an incremental two percent (2%) increase for 2016 and another two percent (2%) increase for 2017. The total incremental wage escalation is added to June 30, 2015 wages to arrive at TEP's adjusted payroll expense.[35]

Q. What is your assessment of TEP's proposal?

A I disagree with TEP's inclusion of a second 2% wage escalation for 2017. The test period in this case is the twelve month period ended June 30, 2015. While the merit of the 2% escalation adjustment for 2016 may be arguable in the context of an historical test period, which is nominally being used in this case, I am prepared to accept this portion of the adjustment as a known and measurable change. However, the second escalator for 2017 extends TEP's pro forma adjustment thirty months beyond the test period. I believe this is far too much of a stretch.

Q. What is your recommendation to the Commission regarding payroll expense?

[34] Direct Testimony of Frank P. Marino, p. 31.
[35] TEP's Income – Payroll Expense workpaper.

A. TEP's use of a second 2% payroll expense escalator for 2017 should be rejected. I present my adjustment to TEP's proposal in Exhibit KCH-8, which also includes a conforming adjustment to TEP's payroll tax expense adjustment. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.222** million relative to TEP's filed case.

Q. Do you have any other concerns regarding TEP's proposed escalation of labor-related costs?

A. Yes. My concerns regarding the escalation of short-term incentive compensation expense are discussed in below. Further, TEP intended to include escalation of 2% for 2016 and 2% for 2017 of its contribution to employees' 401(k) plan, and medical, dental, vision, life and long-term disability costs in the revenue requirement.[36] However, this adjustment was apparently inadvertently omitted from TEP's original Pension and Benefits adjustment. Consistent with my recommendation above regarding 2017 escalation of payroll expenses, I recommend that the Commission reject TEP's 2% escalation of benefits O&M expenses for 2017 because it is overreaching. Although TEP's benefits adjustment is not in its as-filed revenue requirement, the 2017 portion of TEP's adjustment, if adopted, would increase the Total Company revenue requirement by $312,700, and the ACC jurisdictional revenue requirement by approximately $262,380.[37] I recommend against including these increases in any correction to its filing that TEP may offer later in this proceeding.

[36] Direct Testimony of Frank P. Marino, p. 32.
[37] TEP's Income – Pension_Benefits Revised workpaper, provided in TEP's March 18, 2016 Supplemental Response to UDR 1.001.

Short-Term Incentive Compensation

Q. Please describe TEP's short-term incentive compensation plan.

A. All non-union employees are eligible for the short-term incentive plan, called the Performance Enhancement Plan ("PEP"). Short-term incentive compensation payouts are determined by specific PEP metrics. In the 2015 PEP, a Net Income goal received the greatest weighting, at 40 percent. A goal related to O&M Expense containment received a 20 percent weighting. Goals related to Equivalent Availability Factor, System Average Interruption Duration Index, Customer Satisfaction, and OSHA Recordables received a 10 percent weighting each. TEP reports that its 2014 PEP consisted of similar metrics and weightings.[38]

Q. What has TEP proposed with respect to short-term incentive compensation?

A. TEP is proposing to include 100 percent of the PEP expense in rates, based on the average PEP expense for the Test Year and the prior year ended June 30, 2014, including a 2% annual cost escalation assumption applied through 2017.[39]

Q. In your opinion, is it appropriate to recover the cost of short-term incentive plans in utility rates?

A. It can be appropriate to recover the cost of short-term incentive plans in utility rates to the extent that the compensation in such plans is not excessive, and to the extent the goals of such plans are not tied to utility financial performance, but rather to goals such as customer satisfaction, operating efficiency, and safety.

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[38] Direct Testimony of Frank P. Marino, pp. 36-37.
[39] Direct Testimony of Frank P. Marino, pp. 37-38; TEP's Income – Short Term Incentive Compensation workpaper.

While rewarding employees for financial performance can be entirely appropriate, the responsibility for funding such awards rests most appropriately with shareholders, who are the primary beneficiaries of meeting or exceeding financial targets.

Q. What is your recommendation to the Commission regarding recovery of short-term incentive compensation expense?

A. I recommend that shareholders fund 40 percent of the short-term incentive compensation costs, based on the weighting of the 2015 PEP Net Income goal. Arguably, the O&M Expense goal also relates to financial performance, but I am limiting my adjustment to the Net Income goal portion at this time. Similarly to TEP, I calculated my adjustment based on average PEP expense for the Test Year and the prior year ended June 30, 2014. However, consistent with my Payroll Expense adjustment, I recommend that TEP's 2% escalation for 2017 be rejected. I present my adjustment to TEP's proposal in Exhibit KCH-9, which also includes a conforming adjustment to TEP's payroll tax expense adjustment. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.972** million relative to TEP's filed case.

Long-Term Incentive Compensation

Q. Please describe TEP's long-term incentive compensation program.

A. According to the Direct Testimony of Mr. Marino, the long-term incentive ("LTI") compensation program is designed to link a portion of executive officers' compensation to the achievement of multi-year financial results, and serve as a retention tool for executives. LTI awards consist of two components:

performance units and restricted stock units, each subject to a three-year vesting schedule.[40]

According to the 2015 LTI Term Sheet,[41] performance units comprise <BEGIN CONFIDENTIAL>[redacted] and restricted stock units comprise [redacted] of LTI awards. The goals associated with performance units are [redacted]<END CONFIDENTIAL>, the interests of stock awards recipients are naturally aligned with those of shareholders.

Fortis Inc., TEP's parent company, states the following in its *2015 Management Information Circular*, "Medium- and long-term incentives are granted to align executives' interests with those of Shareholders through increasing Shareholder value by fostering Common Share ownership and tying incentive compensation to the value of the Common Shares."[42]

Q. What is TEP proposing with respect to LTI compensation?

A. TEP is proposing to recover the cost of its LTI compensation program in rates, based on the average LTI expense for the Test Year and the prior year ended June 30, 2014.

Q. Did TEP request recovery of LTI compensation in its last general rate case?

[40] Direct Testimony of Frank P. Marino, pp. 40-41.
[41] See TEP's Response to AECC Data Request 4.10, AECC 4.10- 2015 LTI Term Sheet- Confidential, provided in Confidential Exhibit KCH-19.
[42] Fortis Inc. *Notice of Annual Meeting and Management Information Circular* (20 March 2015), p. 48.

A. No. TEP did not request recovery of LTI compensation in its last two general rate cases.[43]

Q. What is your recommendation to the Commission regarding recovery of LTI expense?

A. I recommend that shareholders continue to fund the cost of TEP's LTI compensation program. As financial performance is the focus of the LTI program, the funding of such awards rests most appropriately with shareholders. I believe that continued exclusion of LTI expense from the revenue requirement is appropriate. I present my adjustment to TEP's proposal in Exhibit KCH-10. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.296** million relative to TEP's filed case.

Supplemental Executive Retirement Plan "SERP"

Q. What is a supplemental retirement plan?

A. A supplemental retirement plan, also known as a nonqualified retirement plan, or a "Top Hat Plan", is any plan that does not meet the requirements of Internal Revenue Code Sections 401-416 and therefore lacks the tax advantages conferred upon qualified pension plans. That is, it represents retirement contributions beyond what is included in standard corporate retirement plans. Typically, nonqualified plans are intended to benefit a select group of highly-compensated employees.

Q. Did TEP request recovery of SERP costs in its last general rate case?

A. No.

[43] See TEP's Response to RUCO Data Request 5.2, provided in Exhibit KCH-18.

Q. What is TEP proposing regarding SERP?

A. Unlike its last rate case, TEP is proposing to include the cost of SERP in rates. The SERP expense is included in TEP's Pension and Benefits adjustment.[44]

Q. Do you agree with TEP's proposal to include the cost of SERP in rates?

A. No, I do not. Restraint should be shown in asking customers to fund the extraordinary retirement benefits reflected in nonqualified retirement plans. The cost of these exceptional retirement benefits granted to a select group of highly-compensated employees is most appropriately borne by shareholders, not customers.

Q. What is your recommendation to the Commission regarding recovery of SERP expense?

A. I recommend that SERP expense continue to be excluded from the revenue requirement. I present my adjustment to TEP's proposal in Exhibit KCH-11. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.950** million relative to TEP's filed case.

Severance Expense

Q. What is TEP proposing with respect to severance expense?

A. TEP is requesting to recover severance pay of $365,688, of which $111,835 is capitalized and $253,853 is expensed. TEP justifies this recovery from ratepayers on the grounds that severance costs are incurred in the ordinary course of business.[45]

[44] Direct Testimony of Frank P. Marino, pp. 32-33.
[45] See TEP Response to Staff Data Request 7.14, provided in Exhibit KCH-18.

Q. Do you agree that inclusion of severance expense in the revenue requirement is appropriate?

A. No. Severance expense should only be incurred if there is a net savings from the arrangement. In between rate cases the sole beneficiary of the cost savings from severance packages is the Company, so the Company has a financial incentive to offer cost-saving severance packages without recovery from customers in rates. Moreover, with respect to the ongoing nature of severance arrangements alleged by TEP, I note that TEP has not incorporated any net savings from future severance deals in its payroll expense. Therefore, it is not reasonable to include severance expense in the retail revenue requirement either.

Q. What is your recommendation to the Commission regarding recovery of severance costs?

A. I recommend that severance costs be excluded from the revenue requirement. I present my adjustment to TEP's proposal in Exhibit KCH-12. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$0.218** million relative to TEP's filed case.

Credit Card Processing Fees

Q. What is TEP proposing regarding credit card processing fees?

A. Currently, TEP customers making credit card payments are charged a fee of $3.50 per transaction, which recovers 100% of third-party fees for these transactions. TEP is requesting to reduce the fee charged to customers paying with credit cards to $1.00 per transaction, and charge the balance of the fees to the

Company, for inclusion in operating expenses to be paid by all customers.[46] Further, TEP projects that its reduced credit card fee policy will result in the credit card transaction volume increasing 70 percent over the next three years (2017-2019).[47]

TEP proposes to include in its revenue requirement the annual cost associated with the remaining $2.50 per transaction not borne by credit card paying customers, based on its projected average annual cost over the 2017 through 2019 period, including the escalating transaction volumes that TEP forecasts.

Q. Do you agree with TEP's proposal to change its credit card processing fee policy and pass the remaining costs onto all customers?

A. No, I do not. This problem illustrates one of the challenges in dealing with a regulated monopoly. TEP's current credit card processing fee policy may be an irritant to those customers wishing to pay by credit card, but it properly aligns the transaction cost incurrence with cost recovery. Most businesses avoid annoying their customers with such fees by absorbing the costs of these transactions into their bottom lines, but as a monopoly TEP seeks to transfer these costs to *all other customers* by increasing its requested base revenue requirement. I do not believe it is appropriate to shift the cost responsibility for these fees by reducing the fee charged to customers paying by credit card and then passing the remaining costs onto all customers. Moreover, TEP's proposal to recover a

[46] Direct Testimony of Dallas J. Dukes, p. 58; Direct Testimony of Denise A. Smith, p. 5.
[47] See TEP's Response to RUCO Data Request 5.1, provided in Exhibit KCH-18; TEP's Income – Credit Card Processing Fees workpaper.

portion of the escalation in costs that the Company projects for these fees over the period 2017-2019 is overreaching and unreasonable.

Q. What is your recommendation to the Commission regarding credit card processing fees?

A. I recommend that the entirety of these fees continue to be paid directly by customers who choose to pay their bills with credit cards. I present my adjustment to TEP's proposal in Exhibit KCH-13. My recommended adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$3.482** million relative to TEP's filed case.

Generation Overhaul Expense

Q. What has TEP proposed with respect to generation overhaul expense?

A. Generation overhauls occur over multi-year cycles. For this reason, the expense incurred in any one test period may not be reasonably representative of going-forward expense. To address this concern, it is appropriate to normalize generation overhaul expense using a representative time period.

TEP evaluates generation overhaul expense using both historical and projected data from 2008 through 2024 to determine the frequency of major and minor overhauls. TEP then uses this information to determine an average annual overhaul expense using its projected overhaul expenses for the 2016 to 2024 period. TEP uses the average annual projected overhaul expense as the adjusted test year value.

Q. Do you agree with TEP's approach?

A. No. I do not agree with TEP's use of projected expenses for the 2016 to 2024 period because it is far too speculative. Rather, it is preferable to normalize generation overhaul expense by using historical data over a multi-year period. An exception may be appropriate for *new* facilities for which historical overhaul information is not available.

Q. What is your recommendation to the Commission regarding generation overhaul expense?

A. I recommend that generation overhaul expense be normalized using the historical period, 2012-2015, with one year of actuals and three years of projections for the newly acquired Gila River plant and four years of projections for the newly-converted Sundt Unit 4 plant. This adjustment is presented in Exhibit KCH-14. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$1.865** million relative to TEP's filed case.

Return on Equity

Q. What return on equity is TEP proposing?

A. TEP is proposing a return on equity ("ROE") of 10.35%.[48] This return represents an increase of 35 basis points over the 10.00% ROE approved in Decision No. 73912, issued June 27, 2013, in Docket No. E-01933A-12-0291.

Q. Does AECC support TEP's request?

A. No. Please refer to Exhibit KCH-15, page 2, which shows the ROEs for vertically-integrated electric utilities approved in the United States from January 1, 2012 through December 31, 2012, as reported by SNL Financial. Page 3 of this

[48] See direct testimony of Ann E. Buckley, p. 5.

exhibit shows the ROEs for vertically-integrated electric utilities approved in the country from January 1, 2015 through March 31, 2016, also as reported by SNL Financial.

The median ROE for this group was 10.20% in 2012, the year in which the last TEP rate case was conducted.[49] The 10.00% ROE that TEP was awarded in the last general rate case was 20 basis points below that median. Authorized ROEs in the electric utility industry have fallen since that time. In the 15 months from January 1, 2015 through March 31, 2016, the median approved ROE for vertically-integrated electric utilities was 9.71%. Thus, TEP's proposed ROE of 10.35% is moving in exactly the opposite direction of the trend nationally. If TEP's ROE were to be reset at a rate reflective of the national median, it would be in the vicinity of 9.70%.

Q. If TEP's allowed ROE were to be set at the national median of approximately 9.70%, how would TEP's effective return be impacted by the fair value increment?

A. Unlike the vast majority of utilities in the country, the fair value increment provides Arizona utilities with a premium return above the nominal ROE applied to original cost rate base. Thus, even if TEP's nominal ROE were to remain in line with the national median, TEP's effective ROE would actually be somewhat higher, due to the fair value increment.

[49] TEP filed its Application in that case on July 2, 2012 and the Stipulation in that case was filed on February 4, 2013.

Q. In offering the preceding discussion of national trends, are you intending to supplant the Commission's consideration of traditional cost-of-capital analysis?

A. No. I fully expect that Staff, and perhaps RUCO, will file cost-of-capital analyses for the Commission's consideration, along with that filed by TEP. My discussion of national trends is intended to supplement that analysis.

Q. What would be the revenue requirement impact if TEP's ROE were set at 9.70%?

A. The revenue requirement impact of setting TEP's allowed ROE equal to 9.70% is presented in Exhibit KCH-15, page 1. It reduces TEP's ACC jurisdictional revenue requirement by approximately **$10.826 million** relative to TEP's filed case. I have incorporated an ROE of 9.70% into AECC's overall revenue requirement recommendations at this time, pending further information being presented into the record by other parties.

Jurisdictional Demand Allocation

Q. What is the role of jurisdictional demand allocation in determining the retail revenue requirement in this case?

A. An initial step in determining the retail revenue requirement is the allocation of costs between the retail jurisdiction and the wholesale jurisdiction. This is necessary because a portion of TEP's production plant is devoted to providing long-term sales to wholesale customers. The profits from these sales are retained by TEP and are not credited to retail customers; therefore, it is important that these costs be properly allocated to the wholesale jurisdiction. The allocation of jurisdictional demand is the process by which the share of production fixed costs allocated to the wholesale jurisdiction is determined.

Q. What has TEP proposed in this case regarding jurisdictional demand allocation?

A. TEP has proposed to allocate of 4.34% of its production demand costs to the wholesale jurisdiction. The allocation to the wholesale jurisdiction is intended to capture test period long-term sales commitments to Navajo Tribal Utility Authority, Tohono O'odham Utility Authority, and Trico. However, TEP has made adjustments to exclude from the jurisdictional demand allocation two large long-term sales contracts, Salt River Project ("SRP") and Shell Energy North America ("Shell Energy").[50]

Q. What is TEP's justification for excluding these two long-term sales contracts from the jurisdictional demand allocation?

A. TEP proposes to exclude the SRP contract as a post-test-period adjustment because it expires in May 31, 2016. Similarly, TEP proposes to exclude the Shell Energy contract also as a post-test-period adjustment because it expires December 31, 2017.[51]

Q. How are these two contracts treated for ratemaking purposes today?

A. The SRP contract was assigned <BEGIN CONFIDENTIAL> [redacted] <END CONFIDENTIAL> MW of jurisdictional demand in the last general rate case.[52]

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[50] TEP's Response to Staff Data Request 3.3, STF 3.3 Jurisdictional Allocation-Confidential, provided in Confidential Exhibit KCH-19.

[51] Direct testimony of Michael E. Sheehan, p. 41; TEP's Response to AECC Data Request 7.5, provided in Exhibit KCH-18.

[52] Docket No. E-01933A-12-0291, TEP's 2011 Jurisdictional Allocation 12-31-11 workpaper.

The Shell Energy contract was not signed until December 12, 2014;[53] therefore, it was not included in the jurisdictional demand allocator in that case.

Q. Who is receiving the profits from the Shell Energy sales contract?

A. Currently, all profits from the Shell Energy sales contract accrue 100% to TEP and its shareholders. No benefits accrue to customers.

Q. How is this ratemaking treatment reasonable, considering that the Shell Energy contract was not included in the jurisdictional demand allocation?

A. On a standalone basis this arrangement is <u>not</u> reasonable, given that the Shell Energy sales occur from assets that are paid for by retail customers, without any costs allocated to this contract. However, the settlement agreement negotiated in the last general rate ("2013 Settlement Agreement") included as part of the package a provision that altered TEP's PPFAC Plan of Administration ("POA") to exclude all margins from new long-term sales contracts from the revenues credited to customers in the PPFAC.[54] As a result of this change to the POA, the benefits from the Shell Energy contract accrue solely to TEP and its shareholders. I propose to reverse this change going forward, but I will address this issue separately in my testimony.

Q. Does TEP propose to recognize margins from the Shell Energy contract in the PPFAC going forward?

A. Yes. In combination with excluding the Shell Energy contract from the jurisdictional demand allocation, TEP is proposing to recognize $2.7 million in

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[53] Direct testimony of Michael E. Sheehan, p. 41.

[54] Docket No. E-01933A-12-0291, February 4, 2013 Settlement Agreement, paragraph 6.2; Attachment C.

projected margins from this contract in 2017 base fuel and purchased power costs.[55]

Q. What is your assessment of TEP's proposed jurisdictional demand allocation in this case?

A. I do not object to TEP's adjustment to remove the SRP contract, even though it was in effect during the test period, because the contract ends within twelve months of the conclusion of the test period and there appears to be little likelihood that it will be renewed. However, I recommend against TEP's exclusion of the Shell Energy contract from the jurisdictional demand allocation. Not only was this contract in effect during the test period, it will remain in effect until the end of 2017 – two and a half years beyond the end of the test period. Moreover, per the terms of the change in the POA discussed above, TEP will be the sole beneficiary of the margins from this contract until 2017, when TEP proposes to apply the exception to the adopted PPFAC treatment (discussed above) that would recognize the margins from this contract in base fuel and purchased power costs.

In my view, the expiration date of the contract is too far forward to justify exclusion from a test period ending June 30, 2015. Between now and the expiration date, the contract could be extended or replaced with a new long-term contract to another party which also would not be included in the jurisdictional demand allocation – and the profits from any such replacement contract would flow exclusively to TEP per the current terms of the POA. Moreover, having successfully changed the PPFAC treatment of margins from new long-term

[55] Direct testimony of Michael E. Sheehan, p. 41.

contracts, such as the Shell Energy contract, to its advantage, TEP's proposal to now exclude the Shell Energy contract from the jurisdictional demand allocation strikes me as "cherry-picking," which is unreasonable and should be denied.

Q. What is your recommendation regarding jurisdictional demand allocation?

A. TEP's proposal to adjust the jurisdictional demand allocation to remove the Shell Energy contract should be rejected. I have prepared an adjustment that recalculates the jurisdictional demand allocation factor after assigning the demand associated with this long-term contract to the non-ACC jurisdiction. My adjustment also reverses the $2.7 million credit to customers proposed by TEP for 2017 base fuel and purchased power costs.

Q. What is the revenue requirement impact of adopting your jurisdictional demand allocation adjustment?

A. The revenue requirement impact from my adjustment is presented in Exhibit KCH-16. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$14.043** million relative to TEP's filed case, inclusive of the reversal of the $2.7 million credit to customers proposed by TEP for 2017 base fuel and purchased power costs.

Headquarters Building

Q. What has TEP proposed with respect to recovery of the costs of its headquarters building?

A. TEP has spent approximately $98.7 million related to construction of, and upgrades to, a relatively new headquarters building constructed in downtown

Tucson in 2011.[56] TEP is proposing to include the cost of the headquarters building in rate base, where it would earn a return at the Company's weighted average cost of capital. TEP would also recover the depreciation expense and ongoing operations expense in its proposed revenue requirement.

Q. How is the headquarters building treated in current rates?

A. In the last general rate case, in addition to recovery of expenses, TEP proposed to include the headquarters building in rate base where it would earn a return at the Company's weighted average cost of capital. On behalf of AECC, I objected to that treatment and recommended instead that TEP be allowed to recover its costs, but that the return on its capital invested in the new headquarters building should be limited to the cost of long-term debt. My proposal to limit the return on the headquarters building to the cost of debt was incorporated into the 2013 Settlement Agreement in that case which was approved by the Commission.

Q. Do you agree with TEP's proposal to change the recovery of costs associated with its headquarters to reflect a return at the weighted average cost of capital?

A. No, I do not. While corporate facilities are obviously necessary to conduct business, TEP had corporate facilities prior to the construction of the new facility, albeit less desirable. I believe it is reasonable to ask whether significant outlays on new corporate headquarters constitute the type of "investment" that utilities should be incented to make on par, say, with investments in distribution, generation, and transmission that provide direct benefits or service to customers. In TEP's case, customers are being asked to provide the Company with an equity

[56]TEP Response to AECC Data Request 15.1, AECC 15.1 Support, provided in Exhibit KCH-18.

return on an expensive building[57] that will not provide or deliver a single kilowatt-hour to customers. It is fair to ask whether this type of growth in rate base should be encouraged and rewarded.

In my opinion, it is not reasonable for TEP customers to pay the Company a return on these discretionary expenditures that is comparable to the return on investment in an asset that is more necessary to the provision of electric service. Rather, just as in the last rate case, I propose that TEP be allowed to recover its costs and a return on its capital invested in the new headquarters building, but not at the level of return allowed for its other assets in rate base. Instead, recovery of the headquarters expenditures – plus a carrying charge equal to the cost of long-term debt – is a more appropriate cost recovery treatment. I believe this is a proportionate approach that would fully reimburse the Company for its costs plus a reasonable cost of capital without unjustly enriching the Company for having made this expensive discretionary expenditure.

Q. What is the revenue requirement impact of adopting your proposed ratemaking treatment for the new headquarters building?

A. The revenue requirement impact of limiting TEP's return to the cost of long-term debt for its headquarters building is presented in Exhibit KCH-17. This adjustment reduces TEP's ACC jurisdictional revenue requirement by approximately **$3.552 million** relative to TEP's filed case.

[57] As Staff witness Ralph C. Smith pointed out in TEP's last general rate case, the per-employee cost of the new headquarters was 77% higher than the per-employee cost of TEP's previous headquarters. Docket No. E-01993A-12-0291. Direct Testimony of Ralph C. Smith, p. 24.

PPFAC REVENUE-RELATED ISSUES

Q. What PPFAC revenue-related issues are you addressing?

A. I am addressing two revenue-related issues: (1) the lack of a risk-sharing mechanism in the PPFAC, and (2) the treatment of margins from new long-term contracts.

Q. What is your general view regarding a risk-sharing mechanism in the PPFAC?

A. Although a risk-sharing provision is lacking in the current PPFAC, I am recommending in this case that the Commission approve such a sharing mechanism.

Q. Why do you believe a risk-sharing mechanism is an important feature of a fuel adjustor?

A. A risk-sharing mechanism is essential to keep customer and Company interests aligned. Under the current PPFAC, TEP simply passes through 100% of changes in base fuel and purchased power costs in between rate cases to customers. This type of 100 percent cost pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if it remained exposed to the energy cost risk. It is axiomatic that when a firm stands to gain or lose from its cost management decisions, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs. I strongly recommend against continuing with a PPFAC design that fails to incorporate this natural economic incentive.

Q. But aren't energy costs largely outside a utility's control?

A. Absolutely not. The utility's energy costs are completely out of the customers' control, but not of the utility. Utilities are not mere passive bystanders when it comes to managing power costs. Every hour of every day, utilities need to be managing the dispatch of their systems to achieve minimum costs, subject to the reliability constraints under which they operate. This requires a sophisticated approach to managing utility-owned resources, as well as conducting a large volume of transactions – purchases and sales – throughout the year. The depth and breadth of this around-the-clock dispatch and balancing requirement is so extensive that it is inadvisable for regulators to rely solely on after-the-fact prudence audits to ensure sound utility cost-management performance; rather it is far preferable for the Commission to harness the natural economic self-interest of the company to incentivize the desired behavior of ensuring sound utility cost-management performance.

Q. Are there other aspects of managing fuel and purchased power costs that are important besides optimizing system dispatch?

A. Yes. In addition to hourly dispatch, TEP enters into numerous transactions throughout the course of the year that impact its fuel and purchased power costs, such as short- and long-term purchases and sales and fuel procurement. For example, TEP transacted for nearly 3.5 billion kilowatt-hours short-term power purchases in 2015, valued at over $102 million, consummated with more than 50 counterparties. The Company also made more than 4.5 billion kilowatt-hours of short-term sales in 2015, worth more than $129 million, transacted with more than 40 counterparties.[58] It is critical that TEP have the proper incentives for these transactions to produce the greatest possible net benefit to customers. This incentive is most efficiently implemented by a regime in which TEP shares in the benefits and risks of its decisions.

Q. How else do incentives play a role?

A. Incentives also play an important role with respect to the Company's own operations. For example, it is important for TEP to schedule plant maintenance in a manner that takes into account the impact on power costs. By scheduling outages when replacement power is likely to be less or least expensive, the Company is able to control its power costs. A sharing mechanism gives the Company an economic incentive to take proper account of power costs when scheduling outages. Further, under a sharing mechanism, if the Company experiences forced outages that are more frequent or of greater duration than is reasonably projected in rates, the Company shares in the economic consequences of these events. Likewise, if forced outages are less frequent than had been reasonably projected, the Company shares in the benefit of such superior performance. None of this occurs with a 100% pass-through to customers.

Q. Does TEP hedge a portion of its fuel and purchased power costs?

A. Yes. When a utility hedges its fuel and/or purchased power costs, it is effectively locking in the cost of fuel and/or purchased power that is expected to be consumed in the future. <BEGIN CONFIDENTIAL>[redacted]

[58] Source: TEP 2015 FERC Form 1, pp. 310-11; 326-27.

[redacted][59]<END CONFIDENTIAL>

So while it is correct that utilities do not control the market price of natural gas, for example, it is nevertheless the case that a utility's *decisions* in executing its natural gas hedging strategy (e.g., timing, magnitude) have a large influence on the cost of gas that it ultimately incurs and the fuel costs that are passed on to customers.

Q. If TEP locks in forward fuel prices at prices that later decline, how are these costs treated for ratemaking purposes?

A. In a general rate case, under the current operation of the PPFAC, if the hedged price exceeds the projected market price, the difference is included as a component of fuel cost for full recovery from customers, subject only to prudency considerations. Conversely, if the hedged price is below the projected market price, this difference is credited against the fuel cost recovered from customers. In between rate cases, these differences are included in the PPFAC, and passed through 100 percent to customers.

Q. How does your proposal to introduce risk sharing in the PPFAC affect the sharing of risks related to TEP's hedging decisions?

A. Under the current arrangement, there is no risk whatsoever to TEP from its hedging decisions: short of a prudency disallowance, 100 percent of the risk from TEP's hedging decisions is borne by customers.

Under my proposal, if TEP's hedges turn out to cost more than was projected at the time of the general rate case, the Company shares in this cost;

[59] Source: Confidential TEP Response to UDR 1.098.

similarly, if the Company's hedging decisions prove to reduce fuel costs below what was projected in the general rate case, TEP shares in this gain.

Q. **Do you believe that the threat of a prudency disallowance is sufficient incentive to fully align utility and customer interests in managing fuel costs in between rate cases?**

A. No. In my view, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for a utility having "skin in the game" when it comes to managing its fuel costs. A finding of imprudence essentially requires a determination that a utility acted <u>unreasonably</u> in its power cost management. In contrast, a risk-sharing mechanism structured such that each and every transaction affects the Company's bottom line, provides an incentive for the Company to get the *best possible deal* from every transaction. Striving to get the best possible deal from every transaction is different from simply not behaving unreasonably. Getting the best possible deal is a more exacting and efficient aspiration. A well-crafted sharing mechanism supports this objective.

Q. **Do other utility commissions in the Western United States require a sharing mechanism as part of power supply adjustors?**

A. Yes. Oregon, Washington, Idaho, Montana and Wyoming have each adopted sharing mechanisms that apply to electric utility power cost adjustors approved in those states.

Q. **Please describe the sharing mechanisms used in these other states.**

A. In Oregon, the power cost adjustors of both Pacific Power and Portland General Electric are subject to an asymmetrical dead band ranging from negative $15 million to positive $30 million on Oregon jurisdictional basis. The utility absorbs or retains power cost variances within the dead band. Outside the dead band, a 90/10 sharing mechanism applies, with customers absorbing 90% of incremental costs above the dead band and receiving 90% of the benefits below the dead band. Further, recovery through the power cost adjustors is subject to an earnings test, with zero recovery or refund if the utility's actual ROE is within 100 basis points of its authorized level.[60]

In Pacific Power's Washington jurisdiction, the power cost adjustor is subject to a $4 million dead band. Asymmetrical sharing bands apply for net power cost variances between $4 million and $10 million, with 50/50 sharing applying to positive variances (net power cost under-recovery) and 75% customer/25% utility sharing applying to negative variances (net power cost over-recovery). Net power cost variances exceeding $10 million are subject to a symmetrical 90% customer/10% utility sharing provision.[61]

The latest version of Puget Sound Energy's power cost adjustor in Washington, effective January 1, 2017, includes a $17 million dead band. For variances between $17 million and $40 million, 50/50 sharing applies to positive variances and 65% customer/35% utility sharing applies to negative variances. For variances exceeding $40 million, 90% customer/10% utility sharing applies.[62]

Rocky Mountain Power's Idaho power cost adjustor contains a 90% customer/10% utility sharing mechanism for most components[63], and Montana-

[60] Pacific Power's Oregon power cost adjustment mechanism was adopted in OR Docket No. UE-246, Order No. 12-493 (December 20, 2012). Portland General Electric's power cost adjustment mechanism was adopted in OR Docket Nos. UE-180/UE-181/UE-184, Order No. 07-015 (January 12, 2007). The current mechanism is described in Portland General Electric's Schedule 126.
[61] WA Dockets UE-140762, *et al.*, Order 09 (May 26, 2015).
[62] WA Dockets UE-130617, *et al.*, Order 11 (August 7, 2015), Attachment A to Settlement Stipulation.
[63] ID Case No. PAC-E-15-09, Order 33440 (December 23, 2015).

Dakota Utilities Co.'s power cost adjustor in Montana also contains a 90/10 sharing mechanism.[64]

A 70% customer/30% utility sharing provision was adopted for Rocky Mountain Power's Wyoming power cost adjustor in 2011.[65] In its most recent Wyoming general rate case, Rocky Mountain Power proposed to replace the 70/30 sharing provision with a 100% pass-through to customers. However, the Wyoming commission rejected Rocky Mountain Power's proposal, retaining the 70/30 sharing provision in order to incent the utility to improve its base net power cost forecasts and control net power costs.[66]

Q. In your opinion, does the 70/30 sharing arrangement ordered by the Wyoming commission strike a reasonable balance between utility and customer interests?

A. Yes, it does. This sharing ratio places the substantial majority of responsibility for recovering base fuel cost deviations on customers, but it meaningfully aligns utility and customer interests through shared benefits and costs.

Q. Should this Commission consider adopting the 70/30 sharing provision as utilized in Wyoming?

A. Yes. I encourage the Commission to consider adopting the 70/30 sharing provision that was approved in Wyoming, rather than retaining the current 100/0 approach.

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[64] Montana-Dakota Utilities Co.'s Fuel and Purchased Power Cost Tracking Adjustment – Rate 58.
[65] WY Docket No. 20000-368-EA-10, Memorandum Opinion, Findings and Order (February 4, 2011).
[66] WY Docket No. 20000-469-ER-15, Memorandum Opinion, Findings of Fact, Decision and Order (December 30, 2015), p. 32.

Q. Turning to the second PPFAC-related topic you are addressing, what is your general view concerning the treatment of margins from long-term contracts in a fuel adjustor?

A. If a long-term sales contract is not assigned fixed production cost responsibility in the determination of inter-jurisdictional demand allocation, then the margins from those sales should be credited to customers in the same proportion as any sharing mechanism generally applicable to the fuel adjustor. So, for example, under the current PPFAC, which has no sharing mechanism, 100% of the margins from new long-term contracts that go into effect in between rate cases properly should be credited to customers, because such new long-term contracts would not be allocated any demand costs in the preceding general rate case. By the same token, if a 70/30 PPFAC sharing mechanism is adopted, then 70% of the margins should be credited to customers, consistent with the split of the overall sharing mechanism.

Q. What has been the recent history regarding the treatment of margins from long-term contracts?

A. Prior to the last general rate case, the margins from all wholesale transactions, irrespective of the duration of the contract, were credited to customers in the PPFAC, except for the margins from those long-term contracts that were used in the calculation of the jurisdictional demand allocation. The exclusion of these latter margins made sense because those long-term contracts were allocated a share of system production demand costs.

But in the last general rate case, TEP proposed to change the POA in a way that assigned 100% of the margins from new contracts longer than one year to the benefit of shareholders rather than customers. On behalf of AECC, I strongly opposed this change. However, this provision was included in the 2013 Settlement Agreement approved by the Commission in that case, which AECC supported as a package.

Q. What is your recommendation to the Commission regarding the treatment of margins from long-term contracts in this proceeding?

A. With the filing of this general rate case, this issue should be re-examined. In general, <u>all revenues from wholesale sales, irrespective of term, should be credited against fuel and purchased power costs and included in the PPFAC</u>, unless such sales are allocated a share of system costs. Consequently, the change in the POA approved in the last general rate case that shifted all the benefits from new long-term contracts from customers to shareholders should be reversed.

The generating resources that are used to make these sales are paid for by TEP customers. Consequently, in between rate cases, 100% of the margins from new long-term sales should be included in the PPFAC. If my proposal for risk sharing is adopted, 70% of the margins from new long-term sales (in between rate cases) should be credited to customers in the PPFAC and 30% to TEP. If my proposal for risk sharing is not adopted, then 100% of the margins should be credited to customers in the PPFAC.

<u>ENVIRONMENTAL COMPLIANCE ADJUSTOR</u>

Q. What is the Environmental Cost Adjustor ("ECA")?

A. The ECA allows recovery, with a cap, of government-mandated environmental compliance costs. Specifically, it allows TEP to pass through to customers in between rate cases the incremental costs of its qualifying environmental compliance investments, including return on investment, depreciation expense, taxes and associated O&M cost. The ECA was initiated pursuant to the 2013 Settlement Agreement approved in the last general rate case. The cap is set at 0.25% of TEP's total retail revenue.

Q. What has TEP proposed with respect to the ECA in this case?

A. TEP is proposing to double the cap to 0.50% of retail revenue. According to TEP witness Craig A. Jones, this change would increase revenues recovered through the ECA from $2 million to $4 million per year.[67]

Q. Do you agree with TEP's proposed doubling of the cap?

A. No. The ECA was included in the 2013 Settlement Agreement as a compromise. Many parties, including AECC, opposed the adoption of the ECA in the first instance, but a significant consideration in allowing the ECA to be included in the 2013 Settlement Agreement was the negotiated cap and its agreed-upon magnitude. I recommend against continuation of the ECA unless the specific cap of 0.25% of TEP's total retail revenue is retained. Otherwise, the ECA is an example of unwarranted single-issue ratemaking.

Q. What is single-issue ratemaking?

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

[67] Direct testimony of Craig A. Jones, p. 81.

When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just certain factors in isolation. Considering some costs or revenues in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. For example, the proposed ECA would allow TEP to earn a return on its new investment and charge customers for depreciation expenses associated with that new investment without recognizing that its existing rate base would have depreciated to a lower value at the time the ECA is charged to customers. In my opinion, the proposed ECA is a classic example of an application of single-issue ratemaking that is not in the public interest. I recommend that the ECA be terminated unless it is capped at the previously-negotiated 0.25% of TEP's total retail revenue.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT KCH-1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

As Adjusted by AECC

Line No.	Description	ACC Jurisdiction Original Cost		RCND		Fair Value (FV)	
1	Adjusted Rate Base	$1,989,942	(a)&(b)	$3,549,687	(a)&(b)	$2,769,815	
2	Adjusted Operating Income	110,844	(c)	$110,844	(c)	$110,844	
3	Current Rate of Return (Ln. 2 ÷ Ln. 1)	5.57%		3.12%		4.00%	
4	Required Operating Income on OCRB @ WACC	$139,527		$139,527		$139,527	
5	Required Return on FV Increment	$12,166		$12,166		$12,166	
6	Required Operating Income	$150,601		$150,601		$150,601	
7	Weighted Average Cost of Capital	7.01%	(d)	7.01%		7.01%	
8	Fair Value Adjustment	0.56%		-2.77%		-1.57%	
9	Required Rate of Return (Ln. 6 ÷ Ln. 1)	7.57%	(d)	4.24%		5.44%	
10	Operating Income Deficiency (Ln. 6 - Ln. 2)	$39,757		$39,757		$39,757	
11	Gross Revenue Conversion Factor	1.6223	(e)	1.6223	(e)	1.6223	(e)
12	Increase in Gross Revenue Requirement (Ln. 10 x Ln. 11)	$64,499		$64,499		$64,499	
13	AECC Recommended Return on Headquarters Adjustment	($3,552)	(f)	($3,552)		($3,552)	
14	Net Increase in Gross Revenue Requirement (Ln. 12 + Ln. 13 + Ln. 14)	$60,947		$60,947		$60,947	
15	Adjusted Present Retail Revenues	$909,303	(g)	$909,303		$909,303	
16	Percent Change from Present Revs. (Ln. 15 ÷ Ln. 16)	6.70%		6.70%		6.70%	
17	TEP Claimed Revenue Deficiency	$109,534		$109,534		$109,534	
18	TEP Percent Change from Present Revs. (Ln. 18 ÷ Ln. 16)	12.05%		12.05%		12.05%	
19	AECC Change from TEP Claimed Revenue Deficiency (Ln. 15 - Ln. 18)	($48,587)		($48,587)		($48,587)	
20	AECC Percent Change from TEP Claimed Revenue Deficiency (Ln. 17 - Ln. 19)	-5.34%		-5.34%		-5.34%	

Supporting Schedules/Exhibits
(a) TEP Schedule B-1
(b) AECC Exhibit KCH-1, p. 7
(c) AECC Exhibit KCH-1, p. 4
(d) TEP Schedule D-1
(e) TEP Schedule C-3
(f) AECC Exhibit KCH-17, p. 1
(g) TEP Schedule C-3

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

As Filed by TEP

Line No.	Description	ACC Jurisdiction: Original Cost (OCRB)		RCND		Fair Value (FV)	
1	Adjusted Rate Base	$2,104,678	(a)	$3,721,880	(a)	$2,913,279	
2	Adjusted Operating Income	$98,381	(b)	$98,381	(b)	$98,381	
3	Current Rate of Return (Ln. 2 ÷ Ln. 1)	4.67%		2.64%		3.38%	
4	Required Operating Income on OCRB @ WACC	$154,416		$154,416		$154,416	
5	Required Return on FV Increment	$11,482		$11,482		$11,482	
6	Required Operating Income	$165,898		$165,898		$165,898	
7	Weighted Average Cost of Capital (WACC)	7.34%	(c)	7.34%		7.34%	
8	Fair Value Adjustment	0.54%		-2.88%		-1.64%	
9	Required Rate of Return (Ln. 6 ÷ Ln. 1)	7.88%	(c)	4.46%		5.69%	
10	Operating Income Deficiency (Ln. 6 - Ln. 2)	$67,517		$67,517		$67,517	
11	Gross Revenue Conversion Factor	1.6223	(d)	1.6223	(d)	1.6223	(d)
12	Increase in Gross Revenue Requirement (Ln. 10 x Ln. 11)	$109,534		$109,534		$109,534	
13	Adjusted Present Retail Revenues	$909,325	(e)	$909,325		$909,325	
14	Percent Change from Present Revs. (Ln. 12 ÷ Ln. 13)	12.05%		12.05%		12.05%	

Supporting Schedules
(a) TEP Schedule B-1
(b) TEP Schedule C-1
(c) TEP Schedule D-1
(d) TEP Schedule C-3
(e) TEP Schedule H-1

Summary of AECC Proposed Cost of Capital

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.	Capital Source		Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Cost of Capital
	AECC Proposed	(a)				
1	Short-Term Debt		N/A	N/A	N/A	N/A
2	Long-Term Debt - Net		1,441,656	49.97%	4.32%	2.16%
3	Common Stock Equity		1,443,610	50.03%	9.70%	4.85%
4	Total Capital		$2,885,266	100.00%		7.01%
	TEP Proposed - End of Test Period	(b)				
5	Short-Term Debt		$0	0.00%	0.00%	0.00%
6	Long-Term Debt - Net		$1,441,656	49.97%	4.32%	2.16%
7	Common Stock Equity		1,443,610	50.03%	10.35%	5.18%
8	Total Capital		$2,885,266	100.00%		7.34%

Supporting Schedules/Exhibits
(a) AECC Exhibits KCH-15
(b) TEP Schedule D-1, p. 1 of 2

Summary of AECC Revenue Requirement Adjustments

Operating Revenues and Expenses
Test Year Ended June 30, 2015
(Thousands of Dollars)

		TEP Total Company (a)			AECC Total Company (b)		TEP ACC Jurisdictional (a)			AECC ACC Jurisdictional (b)	
Line No.	Description	Unadjusted	Pro Forma Adjustments	Total Adjusted	Pro Forma Adjustments	Total Adjusted	ACC Jurisdiction Unadjusted	Pro Forma Adjustments	ACC Jurisdiction Adjusted	Pro Forma Adjustments	ACC Jurisdiction Adjusted
1	Operating Revenues										
2	Electric Retail Revenues	606,322	($944)	$605,378	($2,702)	$602,676	$606,322	($944)	605,378	($2,702)	$602,676
3	PPFAC Revenue	325,588	($21,663)	303,925	2,702	306,626	$325,588	($21,663)	303,925	2,702	306,626
4	Sales for Resale	162,821	(162,821)	(0)	0	(0)	0	0	0	0	0
5	Other Operating Revenue	223,661	($172,841)	50,820	0	50,820	204,570	(172,841)	31,729	0	31,729
6	Total Operating Revenues	1,318,392	(358,269)	960,122	(0)	960,122	1,136,480	(195,448)	941,031	0	941,031
7	Operating Expenses										
8	Fuel Expense	292,405	11,521	303,926	2,702	$306,627	244,771	59,155	303,926	2,702	306,627
9	Purchased Power - Demand	1,405	(1,405)	0	0	0	0	0	0	0	0
10	Purchased Power - Energy	192,581	(192,581)	(0)	0	(0)	0	(0)	(0)	0	(0)
11	Transmission	6,205	(6,205)	0	0	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	492,596	(188,671)	303,926	2,702	306,627	244,771	59,155	303,926	2,702	306,627
13	Other Operations and Maintenance Expense	417,887	(136,826)	281,061	(13,793)	267,268	366,742	(31,811)	334,931	(16,985)	317,946
14	Depreciation	143,586	13,306	156,891	(2,389)	154,503	118,030	11,673	129,703	(6,392)	123,310
15	Taxes Other than Income Taxes	50,111	3,205	53,315	(324)	52,992	39,180	1,555	40,735	(1,020)	39,715
16	Income Taxes	60,050	(19,574)	40,476	0	40,476	49,486	(16,130)	33,356	9,232	42,588
17	Total Operating Expenses	1,164,231	(328,560)	835,670	(13,804)	821,866	818,209	24,442	842,650	(12,463)	830,187
18	Operating Income	154,161	($29,709)	$124,452	$13,804	$138,256	318,271	(219,890)	$98,381	$12,463	$110,844
19	Other Income and Deductions										
20	Allowance for Equity Funds	4,572									
21	Other - Net	3,022									
22	Total Other Income and Deductions	7,594									
23	Income Before Interest Expense	161,755									
24	Interest Expense										
25	Interest on Long-Term Debt	56,729									
26	Interest on Short-Term Debt	909									
27	Other Interest Expense	4,497									
28	Allowance for Borrowed Funds	(2,922)									
29	Total Interest Expense	59,213									
30	Income Before Cumulative Effect of Accounting Change	102,542									
31	Cumulative Effect of Accounting Change - Net of Tax	0									
32	Net Income Available for Common Stock	$102,542									

Supporting Schedules/Exhibits/Data Source
(a) TEP Schedule C-1 and TEP Rev. Req't Model
(b) AECC Exhibit KCH-1, p. 7

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.		Bonus Tax Depreciation Expense ADIT Adjustment		Sundt & San Juan 2 M&S Regulatory Asset Adjustment		50.5% Co-Ownership of SGS 1 Regulatory Asset Adjustment	
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	0	0	0	0
3	PPFAC Revenue	0	0	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	0	0	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	0	0	0	0
13	Other Operations & Maintenance Expense	0	0	0	0	0	0
14	Depreciation and Amortization	0	0	0	0	(2,389)	(2,145)
15	Taxes Other than Income	0	0	0	0	0	0
16	Income Taxes	0	106	0	3	0	1,016
17	Total Operating Expenses	0	106	0	3	(2,389)	(1,128)
18	Operating Income	0	(106)	0	(3)	2,389	1,128
19	Rate Base - Original Cost	(15,887)	(12,814)	(409)	(409)	(23,887)	(23,887)
20	Rate Base - RCND	(34,299)	(27,664)	(409)	(409)	(23,887)	(23,887)

Line No.		Springerville Unit 1 2006 Lease Acquisition Adjustment		Springerville Unit 1 Capitalized Legal Expense Adjustment		Springerville Unit 1 Legal Expense Adjustment	
		Total Company (g)	ACC Jurisdictional (h)	Total Company (i)	ACC Jurisdictional (j)	Total Company (k)	ACC Jurisdictional (l)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	0	0	0	0
3	PPFAC Revenue	0	0	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	0	0	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	0	0	0	0
13	Other Operations & Maintenance Expense	0	0	0	0	(1,598)	(1,340)
14	Depreciation and Amortization	0	0	0	0	0	0
15	Taxes Other than Income	0	0	0	0	0	0
16	Income Taxes	0	121	0	7	0	513
17	Total Operating Expenses	0	121	0	7	(1,598)	(828)
18	Operating Income	0	(121)	0	(7)	1,598	828
19	Rate Base - Original Cost	(16,188)	(14,675)	(919)	(835)	0	(0)
20	Rate Base - RCND	(9,421)	(9,202)	(919)	(836)	0	(0)

Supporting Exhibits
(a) & (b) AECC Exhibit KCH-2, p. 1
(c) & (d) AECC Exhibit KCH-3, p. 1
(e) & (f) AECC Exhibit KCH-4, p. 1
(g) & (h) AECC Exhibit KCH-5, p. 1
(i) & (j) AECC Exhibit KCH-6, p. 1
(k) & (l) AECC Exhibit KCH-7, p. 1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.		Payroll Expense Adjustment		Short-Term Incentive Compensation Expense Adjustment		Long-Term Incentive Compensation Expense Adjustment	
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)
1	Operating Revenues						
2	Electric Retail Revenues	14	14	0	0	0	0
3	PPFAC Revenue	(14)	(14)	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	(0)	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	(14)	(14)	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	(14)	(14)	0	0	0	0
13	Other Operations & Maintenance Expense	(1,365)	(1,130)	(2,484)	(1,773)	(1,542)	(1,294)
14	Depreciation and Amortization	0	0	0	0	0	0
15	Taxes Other than Income	(91)	(76)	(233)	(195)	0	0
16	Income Taxes	0	467	0	753	0	495
17	Total Operating Expenses	(1,469)	(753)	(2,716)	(1,216)	(1,542)	(799)
18	Operating Income	1,469	753	2,716	1,216	1,542	799
19	Rate Base - Original Cost	0	(0)	0	(0)	0	(0)
20	Rate Base - RCND	0	(0)	0	(0)	0	(0)

Line No.		SERP Expense Adjustment		Severance Expense Adjustment		Credit Card Processing Fees Expense Adjustment	
		Total Company (g)	ACC Jurisdictional (h)	Total Company (i)	ACC Jurisdictional (j)	Total Company (k)	ACC Jurisdictional (l)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	0	0	0	0
3	PPFAC Revenue	0	0	0	0	0	0
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	0	0	0	0
7	Operating Expenses						
8	Fuel Expense	0	0	0	0	0	0
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	0	0	0	0
13	Other Operations & Maintenance Expense	(1,130)	(948)	(254)	(218)	(3,476)	(3,476)
14	Depreciation and Amortization	0	0	0	0	0	0
15	Taxes Other than Income	0	0	0	0	0	0
16	Income Taxes	0	363	0	83	0	1,329
17	Total Operating Expenses	(1,130)	(585)	(254)	(135)	(3,476)	(2,146)
18	Operating Income	1,130	585	254	135	3,476	2,146
19	Rate Base - Original Cost	0	(0)	0	(0)	0	0
20	Rate Base - RCND	0	(0)	0	(0)	0	0

Supporting Exhibits
(a) & (b) AECC Exhibit KCH-8, p. 1
(c) & (d) AECC Exhibit KCH-9, p. 1
(e) & (f) AECC Exhibit KCH-10, p. 1
(g) & (h) AECC Exhibit KCH-11, p. 1
(i) & (j) AECC Exhibit KCH-12, p. 1
(k) & (l) AECC Exhibit KCH-13, p. 1

Summary of AECC Revenue Requirement Adjustments

Test Year Ended June 30, 2015
(Thousands of Dollars)

Line No.		Generation Overhaul Expense Adjustment		Jurisdictional Allocation Adjustment		Total Adjustments	
		Total Company (a)	ACC Jurisdictional (b)	Total Company (c)	ACC Jurisdictional (d)	Total Company (e)	ACC Jurisdictional (f)
1	Operating Revenues						
2	Electric Retail Revenues	0	0	(2,715)	(2,715)	(2,702)	(2,702)
3	PPFAC Revenue	0	0	2,715	2,715	2,702	2,702
4	Sales for Resale	0	0	0	0	0	0
5	Other Operating Revenue	0	0	0	0	0	0
6	Total Operating Revenues	0	0	(0)	0	(0)	0
7	Operating Expenses						
8	Fuel Expense	0	0	2,715	2,715	2,702	2,702
9	Purchased Power - Demand	0	0	0	0	0	0
10	Purchased Power - Energy	0	0	0	0	0	0
11	Transmission	0	0	0	0	0	0
12	Fuel, Purchased Power and Transmission	0	0	2,715	2,715	2,702	2,702
13	Other Operations & Maintenance Expense	(1,946)	(1,862)	0	(4,944)	(13,793)	(16,985)
14	Depreciation and Amortization	0	0	0	(4,248)	(2,389)	(6,392)
15	Taxes Other than Income	0	0	0	(748)	(324)	(1,020)
16	Income Taxes	0	712	0	3,265	0	9,232
17	Total Operating Expenses	(1,946)	(1,150)	2,715	(3,960)	(13,804)	(12,463)
18	Operating Income	1,946	1,150	(2,715)	3,960	13,804	12,463
19	Rate Base - Original Cost	0	(0)	0	(62,117)	(57,289)	(114,736)
20	Rate Base - RCND	0	(0)	0	(110,196)	(68,935)	(172,193)

EXHIBIT KCH-2

AECC Bonus Tax Depreciation Expense ADIT Adjustment

Line No.		Total Company AECC Bonus Tax Depr. ADIT Adjustment ($000) (a)	Jurisdictional AECC Bonus Tax Depr. ADIT Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	106		16
17	Total Operating Expenses	0	106		17
18	Operating Income	0	(106)		18
19	Rate Base - Original Cost	(15,887)	(12,814)		19
20	Rate Base - RCND	(34,299)	(27,664)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		172		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(1,525)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		(171)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(1,525)}$		25

<u>Supporting Schedules/Data Source</u>
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Bonus Tax Depreciation Expense ADIT Adjustment

Line No.	Description	FERC Acct	AECC Recommended[1] Total Company Amount	AECC Recommended[1] ACC Jurisdictional Allocation Percent	AECC Recommended[1] ACC Jurisdictional Amount	TEP Proposed[2] Total Company Amount	TEP Proposed[2] ACC Jurisdictional Allocation Percent	TEP Proposed[2] ACC Jurisdictional Amount	AECC Adjustment Total Company Amount	AECC Adjustment ACC Jurisdictional Allocation Percent	AECC Adjustment ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Accumulated Deferred Income Taxes (ADIT)	190	($168,923,600)	80.66%	($136,246,714)	($175,121,198)	80.66%	($141,245,438)	$6,197,598	80.66%	$4,998,723
2	Accumulated Deferred Income Taxes (ADIT) - Other Property	282	$19,241,437	80.66%	$15,519,339	$41,326,508	80.66%	$33,332,234	($22,085,071)	80.66%	($17,812,895)
3	Accumulated Deferred Income Taxes (ADIT) - Other	283	$51,043,022	97.18%	$49,604,518	$51,043,022	97.18%	$49,604,518	$0	97.18%	$0
4	Total ADIT		($98,639,141)		($71,122,857)	($82,751,668)		($58,308,685)	($15,887,473)		($12,814,172)

1. Data Source: TEP Response to AECC Data Request No. 1.3.
2. Data Source: TEP Pro Forma Rate Base - Accumulated Deferred Income Taxes Workpaper.

EXHIBIT KCH-3

AECC Sundt & San Juan 2 Material & Supplies Regulatory Asset Adjustment

Line No.		Total Company AECC Sundt & San Juan 2 M&S Adjustment ($000) (a)	Jurisdictional AECC Sundt & San Juan 2 M&S Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	3		16
17	Total Operating Expenses	0	3		17
18	Operating Income	0	(3)		18
19	Rate Base - Original Cost	(409)	(409)		19
20	Rate Base - RCND	(409)	(409)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		5		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(49)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(43)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Sundt & San Juan 2 Material & Supplies Regulatory Asset Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Regulatory Asset (Beginning Balance)		$1,225,594	100.0%	$1,225,594	$1,225,594	100.0%	$1,225,594			
2	Less: Accumulated Amortization (Yr 1)		($408,531)		($408,531)	$0		$0			
3	Net Regulatory Asset	182.3	$817,063	100.0%	$817,063	$1,225,594	100.0%	$1,225,594	($408,531)	100.0%	($408,531)
4	Proposed Amortization Period (Yrs)		3		3	3		3			
5	Amortization Expense	407.3	$408,531	100.0%	$408,531	$408,531	100.0%	$408,531	$0	100.0%	$0

1. Data Source: TEP Pro Forma Rate Base - Sundt _ San Juan M_S Workpaper and Income - Sundt-San Juan M_S Workpaper.

EXHIBIT KCH-4

AECC 50.5% Co-Ownership of SGS 1 Adjustment Regulatory Asset Adjustment

Line No.		Total Company AECC Co-Ownership of SGS 1 Adjustment ($000) (a)	Jurisdictional AECC Co-Ownership of SGS 1 Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	(2,389)	(2,145)		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	1,016		16
17	Total Operating Expenses	(2,389)	(1,128)		17
18	Operating Income	2,389	1,128		18
19	Rate Base - Original Cost	(23,887)	(23,887)		19
20	Rate Base - RCND	(23,887)	(23,887)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,830)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(2,843)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.56% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(4,673)}$		25

<u>Supporting Schedules/Data Source</u>
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC 50.5% Co-Ownership of SGS 1 Adjustment Regulatory Asset Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Steam Production Plant in Service										
2	Land & Land Rights	310	$0	100.0%	$0	$1,166,906	100.0%	$1,166,906	($1,166,906)	100.0%	($1,166,906)
3	Structures & Improvements	311	0	100.0%	0	24,028,906	100.0%	24,028,906	(24,028,906)	100.0%	(24,028,906)
4	Boiler Plant Equipment	312	0	100.0%	0	46,602,538	100.0%	46,602,538	(46,602,538)	100.0%	(46,602,538)
5	Turbogenerator Units	314	0	100.0%	0	14,978,815	100.0%	14,978,815	(14,978,815)	100.0%	(14,978,815)
6	Accessory Electric Equipment	315	0	100.0%	0	1,978,251	100.0%	1,978,251	(1,978,251)	100.0%	(1,978,251)
7	Misc. Power Plant Equipment	316	0	100.0%	0	1,327,646	100.0%	1,327,646	(1,327,646)	100.0%	(1,327,646)
8	Total		$0		$0	$90,083,062		$90,083,062	($90,083,062)		($90,083,062)
9	Steam Production Plant Accumulated Depreciation										
10	Land & Land Rights	310	$0	100.0%	$0	($1,372,775)	100.0%	($1,372,775)	$1,372,775	100.0%	$1,372,775
11	Structures & Improvements	311	0	100.0%	0	(18,316,603)	100.0%	(18,316,603)	18,316,603	100.0%	18,316,603
12	Boiler Plant Equipment	312	0	100.0%	0	(32,458,827)	100.0%	(32,458,827)	32,458,827	100.0%	32,458,827
13	Turbogenerator Units	314	0	100.0%	0	(12,249,649)	100.0%	(12,249,649)	12,249,649	100.0%	12,249,649
14	Accessory Electric Equipment	315	0	100.0%	0	(1,266,485)	100.0%	(1,266,485)	1,266,485	100.0%	1,266,485
15	Misc. Power Plant Equipment	316	0	100.0%	0	(532,212)	100.0%	(532,212)	532,212	100.0%	532,212
16	Total		$0		$0	($66,196,552)		($66,196,552)	$66,196,552		$66,196,552
17	Steam Production Plant Net Book Value										
18	Land & Land Rights	310	$0		$0	($205,869)		($205,869)	$205,869		$205,869
19	Structures & Improvements	311	0		0	5,712,303		5,712,303	(5,712,303)		(5,712,303)
20	Boiler Plant Equipment	312	0		0	14,143,711		14,143,711	(14,143,711)		(14,143,711)
21	Turbogenerator Units	314	0		0	2,729,165		2,729,165	(2,729,165)		(2,729,165)
22	Accessory Electric Equipment	315	0		0	711,766		711,766	(711,766)		(711,766)
23	Misc. Power Plant Equipment	316	0		0	795,433		795,433	(795,433)		(795,433)
24	Total		$0		$0	$23,886,510		$23,886,510	($23,886,510)		($23,886,510)
25	Net Regulatory Asset (= Ln. 24)	182.3	$0	100.0%	$0	$23,886,510	100.0%	$23,886,510	($23,886,510)	100.0%	($23,886,510)
26	Regulatory Asset Amortization Expense[2]										
27	Land & Land Rights	310	$0	89.8%	$0	($20,587)	89.78%	($18,484)	$20,587	89.8%	$18,484
28	Structures & Improvements	311	0	89.8%	0	571,230	89.78%	512,866	(571,230)	89.8%	(512,866)
29	Boiler Plant Equipment	312	0	89.8%	0	1,414,371	89.78%	1,269,862	(1,414,371)	89.8%	(1,269,862)
30	Turbogenerator Units	314	0	89.8%	0	272,917	89.78%	245,032	(272,917)	89.8%	(245,032)
31	Accessory Electric Equipment	315	0	89.8%	0	71,177	89.78%	63,904	(71,177)	89.8%	(63,904)
32	Misc. Power Plant Equipment	316	0	89.8%	0	79,543	89.78%	71,416	(79,543)	89.8%	(71,416)
33	Total		$0		$0	$2,388,651		$2,144,597	($2,388,651)		($2,144,597)

1. Data Source: TEP Responses to AECC Data Request No. 10.2 and 16.1.

2. Note: TEP's response to AECC DR No. 16.1 indicates the ACC regulatory asset amortization expense is $2,165,307 derived by using FERC account 310-316 jurisdictional allocation factors. AECC has used the related steam plant depreciation expense jurisdictional allocation factors to develop its adjustment above.

EXHIBIT KCH-5

AECC Springerville Unit 1 2006 Lease Acquisition Rate Base Adjustment

Line No.		Total Company AECC SGS 1 2006 Lease Acquisition Adjustment ($000) (a)	Jurisdictional AECC SGS 1 2006 Lease Acquisition Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	121		16
17	Total Operating Expenses	0	121		17
18	Operating Income	0	(121)		18
19	Rate Base - Original Cost	(16,188)	(14,675)		19
20	Rate Base - RCND	(9,421)	(9,202)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		196		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(1,747)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		63		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,488)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Springerville Unit 1 2006 Lease Acquisition Rate Base Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Plant in Service										
2	Land & Land Rights	310	$264,751	89.8%	$237,701	$223,159	89.8%	$200,358	$41,592	89.8%	$37,343
3	Structures & Improvements	311	10,161,249	89.8%	9,123,052	8,564,917	89.8%	7,689,821	1,596,332	89.8%	1,433,232
4	Boiler Plant Equipment	312	27,966,787	89.8%	25,109,359	23,573,204	89.8%	21,164,678	4,393,582	89.8%	3,944,680
5	Turbogenerator Units	314	7,165,280	95.7%	6,854,205	6,039,615	95.7%	5,777,409	1,125,666	95.7%	1,076,796
6	Accessory Electric Equipment	315	4,348,967	89.8%	3,904,623	3,665,744	89.8%	3,291,207	683,223	89.8%	613,416
7	Miscellaneous Power Plant Equipment	316	770,943	95.7%	737,473	649,828	95.7%	621,616	121,115	95.7%	115,857
8	Total Plant in Service		$50,677,977		$45,966,413	$42,716,467		$38,745,090	$7,961,510		$7,221,324
9	Accumulated Depreciation										
10	Land & Land Rights	310	$126,160	89.8%	$113,270	$0	89.8%	$0	$126,160	89.8%	$113,270
11	Structures & Improvements	311	4,842,084	89.8%	4,347,358	0	89.8%	0	4,842,084	89.8%	4,347,358
12	Boiler Plant Equipment	312	13,326,858	89.8%	11,965,224	0	89.8%	0	13,326,858	89.8%	11,965,224
13	Turbogenerator Units	314	3,414,431	95.7%	3,266,196	0	95.7%	0	3,414,431	95.7%	3,266,196
14	Accessory Electric Equipment	315	2,072,389	89.8%	1,860,649	0	89.8%	0	2,072,389	89.8%	1,860,649
15	Miscellaneous Power Plant Equipment	316	367,373	95.7%	351,424	0	95.7%	0	367,373	95.7%	351,424
16	Total Accumulated Depreciation		$24,149,296		$21,904,121	$0		$0	$24,149,296		$21,904,121
17	Net Plant in Service										
18	Land & Land Rights		$138,591		$124,431	$223,159		$200,358	($84,568)		$0
19	Structures & Improvements		5,319,165		4,775,695	8,564,917		7,689,821	(3,245,752)		0
20	Boiler Plant Equipment		14,639,928		13,144,135	23,573,204		21,164,678	(8,933,276)		0
21	Turbogenerator Units		3,750,849		3,588,009	6,039,615		5,777,409	(2,288,766)		0
22	Accessory Electric Equipment		2,276,578		2,043,975	3,665,744		3,291,207	(1,389,166)		0
23	Miscellaneous Power Plant Equipment		403,570		386,049	649,828		621,616	(246,258)		0
24	Total Plant in Service		$26,528,681		$24,062,293	$42,716,467		$38,745,090	($16,187,786)		($14,682,797)

1. Data Source: TEP Rate Base - SGS Unit 1 Lease Equity Adjustment. FERC amounts derived using FERC account percentages shown on p. 3.

AECC Springerville Unit 1 2006 Lease Acquisition Rate Base Adjustment

Line No.	Description	Total Plant Amount	2006 Purchase Percentage[2]	2006 Purchase Amount
	(a)	(b)	(c)	(d)
1	**Springerville Unit 1 Net Book Value as of 6/30/2015[1]**			
2	Plant in Service - Account 101	$ 359,418,280	14.1%	$ 50,677,977
3	Accumulated Depreciation Reserve - Account 108	171,271,606	14.1%	$24,149,296
4	Net Book Value (= Ln. 1 - Ln. 2)	$ 188,146,674		$ 26,528,681

Line No.	Description	FERC Account	FERC Account Allocation Percent[3]	2006 Purchase Amount
	(a)	(b)	(c)	(d)
5	**Spread of 2006 Net Book Values to FERC Accounts[4]**			
6	**Plant in Service - Account 101**			
7	Land and Land Rights	310	0.5%	264,751
8	Structures and improvements	311	20.1%	10,161,249
9	Boiler plant equipment	312	55.2%	27,966,787
10	Turbogenerator units	314	14.1%	7,165,280
11	Accessory electric equipment	315	8.6%	4,348,967
12	Miscellaneous power plant equipment	316	1.5%	770,943
13	Total			50,677,977
14	**Accumulated Depreciation Reserve - Account 108**			
15	Land and Land Rights	310	0.5%	126,160
16	Structures and improvements	311	20.1%	4,842,084
17	Boiler plant equipment	312	55.2%	13,326,858
18	Turbogenerator units	314	14.1%	3,414,431
19	Accessory electric equipment	315	8.6%	2,072,389
20	Miscellaneous power plant equipment	316	1.5%	367,373
21	Total			24,149,296

1. Data Source: TEP Response to AECC 11.3.
2. Data Source: TEP Witness Kentton Grant Direct Testimony, p. 30.
3. Data Source: TEP Rate Base - SGS Unit 1 Lease Equity Adjustment.
4. The net book value excludes acquisition adjustment and accumulated deferred income tax amounts which appear to be related to TEP's 2015 purchase of 35.4% interest in Unit 1.

EXHIBIT KCH-6

AECC Springerville Unit 1 Capitalized Legal Costs Rate Base Adjustment

Line No.		Total Company AECC SGS 1 2014/15 Cap. Legal Costs Adjustment ($000) (a)	Jurisdictional AECC SGS 1 2014/15 Cap. Legal Costs Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	7		16
17	Total Operating Expenses	0	7		17
18	Operating Income	0	(7)		18
19	Rate Base - Original Cost	(919)	(835)		19
20	Rate Base - RCND	(919)	(836)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		11		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(99)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		(0)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(88)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Springerville Unit 1 Capitalized Legal Costs Rate Base Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Plant in Service										
2	Land & Land Rights	310	$0	89.8%	$0	$4,801	89.8%	$4,311	($4,801)	89.8%	($4,311)
3	Structures & Improvements	311	0	89.8%	0	184,274	89.8%	165,446	(184,274)	89.8%	(165,446)
4	Boiler Plant Equipment	312	0	89.8%	0	507,176	89.8%	455,357	(507,176)	89.8%	(455,357)
5	Turbogenerator Units	314	0	95.7%	0	129,942	95.7%	124,301	(129,942)	95.7%	(124,301)
6	Accessory Electric Equipment	315	0	89.8%	0	78,868	89.8%	70,810	(78,868)	89.8%	(70,810)
7	Miscellaneous Power Plant Equipment	316	0	95.7%	0	13,981	95.7%	13,374	(13,981)	95.7%	(13,374)
8	Total Plant in Service		$0		$0	$919,042		$833,598	($919,042)		($833,598)

1. Data Source: See derivation on p. 3.

AECC Springerville Unit 1 Capitalized Legal Expense Rate Base Adjustment

Line No.	Description (a)		Total Plant Amount (c)
1	**Springerville Unit 1 2014/2015 Acquisition Fee Amount Included in Rate Base[1]**		
2	AECC Recommended Disallowance	$	919,042

Line No.	Description (a)	FERC Account (b)	FERC Account Allocation Percent[2] (c)		FERC Account Amount (d)
3	Spread of Acquisition Fees to FERC Accounts				
4	**Plant in Service - Account 101**				
5	Land and Land Rights	310	0.5%	$	4,801
6	Structures and improvements	311	20.1%		184,274
7	Boiler plant equipment	312	55.2%		507,176
8	Turbogenerator units	314	14.1%		129,942
9	Accessory electric equipment	315	8.6%		78,868
10	Miscellaneous power plant equipment	316	1.5%		13,981
11	Total			$	919,042

1. **Data Source: TEP Response to AECC Data Request No. 10.2 (clarified by D. Lewis e-mail on 5/26/2016).**
2. **Data Source: TEP Rate Base - SGS Unit 1 Lease Equity Adjustment.**

EXHIBIT KCH-7

AECC Springerville Unit 1 Legal Expense Adjustment

Line No.		Total Company AECC SGS 1 Legal Expense Adjustment ($000) (a)	Jurisdictional AECC SGS 1 Legal Expense Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,598)	(1,340)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	513		16
17	Total Operating Expenses	(1,598)	(828)		17
18	Operating Income	1,598	828		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,343)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(1,343)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Springerville Unit 1 Legal Expense Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description (a)	FERC Acct (b)	Total Company Amount (c)	ACC Jurisdictional Allocation Percent (d)	ACC Jurisdictional Amount (e)	Total Company Amount (f)	ACC Jurisdictional Allocation Percent (g)	ACC Jurisdictional Amount (h)	Total Company Amount (i)	ACC Jurisdictional Allocation Percent (j)	ACC Jurisdictional Amount (k)
1	Administrative & General Expenses										
2	Outside Services	923	$0	83.9%	$0	$1,597,513	83.9%	$1,340,437	($1,597,513)	83.9%	($1,340,437)

1. Data Source: TEP Response to AECC Data Request 10.1.

Comparison of Legal Expenses for TEP's Retail Jurisdiction

Line No.		ACC Jurisdiction[1]				
		2011	2012	2013	2014	Test Year 12 Mos. End. 6/30/2015
1	Unadjusted	2,342,462	1,619,431	1,419,891	2,222,637	3,638,621
2	DSM & REST Adjustment	(58,051)				(357,950)
3	Springerville 3 & 4 Adjustment	4,162				(2,395)
4	Power Supply Management					(22,619)
5	Adjusted	2,288,572	1,619,431	1,419,891	2,222,637	3,255,658

Avg. = 1,775,965

Data Sources:
1. TEP Supplemental Response to AECC Data Request 10.1.

EXHIBIT KCH-8

AECC Payroll Expense Adjustment

Line No.		Total Company AECC Payroll Expense Adjustment ($000) (a)	Jurisdictional AECC Payroll Expense Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	14	14		2
3	PPFAC Revenue	(14)	(14)		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	(0)		6
7	Operating Expenses				7
8	Fuel Expense	(14)	(14)		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	(14)	(14)		12
13	Other Operations & Maintenance Expense	(1,365)	(1,130)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	(91)	(76)		15
16	Income Taxes	0	467		16
17	Total Operating Expenses	(1,469)	(753)		17
18	Operating Income	1,469	753		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,222)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,222)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Payroll Expense Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Adjustment	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Operations						
2	Steam Prod Oper-Supervision	500	6,623,859	6,933,211	153,145	6,777,004	(156,208)
3	Fuel - Steam	501	572,531	599,270	13,237	585,768	(13,502)
4	Steam Expenses	502	7,846,852	8,213,321	181,420	8,028,272	(185,049)
5	Electric Expenses	505	2,606,785	2,728,529	60,269	2,667,054	(61,475)
6	Steam Prod-Misc Expense	506	1,930,923	2,021,102	44,643	1,975,566	(45,536)
7	Other Prod Oper-Supervision	546	41,644	43,589	963	42,607	(982)
8	Misc. Other Pw Gen Exp	549	107	112	2	109	(3)
9	Sys Cntrol/Load Dispatch	556	1,081,004	1,131,490	24,993	1,105,997	(25,493)
10	Prod Expense-Other	557	257,063	269,068	5,943	263,006	(6,062)
11	Trans-Oper Supv & Engr	560	1,198,247	1,254,209	27,704	1,225,951	(28,258)
12	Dist-Oper Supv & Engr	580	438,001	458,457	10,127	448,128	(10,329)
13	Dist-Load Dispatching	581	451,781	472,881	10,445	462,227	(10,654)
14	Dist-Station Expenses	582	173,895	182,017	4,020	177,916	(4,101)
15	Dist-Overhead Line Exp	583	405,478	424,415	9,375	414,853	(9,562)
16	Dist-Underground Line Exp	584	188,035	196,817	4,347	192,383	(4,434)
17	Dist-Light/Signal Exp	585	76	79	2	77	(2)
18	Dist-Meter Expenses	586	685,887	717,919	15,858	701,744	(16,175)
19	Dist-Customer Install Exp	587	45,620	47,751	1,055	46,675	(1,076)
20	Dist-Misc Expense	588	3,167,598	3,315,534	73,235	3,240,834	(74,700)
21	Meter Reading Expense	902	439	460	10	449	(10)
22	Cust Rec/Collection Exp	903	6,052,473	6,335,140	139,934	6,192,407	(142,733)
23	Customer Assistance Exp	908	59,761	62,552	1,382	61,142	(1,409)
24	Informational/Instrct Adv Exp	909	6,315	6,610	146	6,461	(149)
25	A&G Salaries	920	20,958,164	21,936,965	484,556	21,442,720	(494,245)
26	Outside Services	923	62,512	65,431	1,445	63,957	(1,474)
27	Injuries & Damages	925	67,970	71,145	1,571	69,542	(1,603)
28	Pensions & Benefits	926	1,278,055	1,337,744	29,549	1,307,604	(30,140)
29	Misc. General Expenses	930	171,654	179,671	3,969	175,623	(4,048)
30	Load Dispatch-Reliability	5611	686,184	718,231	15,865	702,049	(16,182)
31	Load Dispatch-Monitor and Operation Transmiss	5612	807,012	844,701	18,658	825,670	(19,031)
32	Load Dispatch-Transmission Service and Schedu	5613	582,935	610,159	13,478	596,412	(13,747)
33	Total Operations	Various	58,448,862	61,178,579	1,351,346	59,800,208	(1,378,372)
34	Total Maintenance	Various	18,330,858	18,330,858	0	18,330,858	-
35	Total Operations & Maintenance	Various	76,779,720	79,509,437	1,351,346	78,131,065	(1,378,372)
36	Taxes Other Than Income Taxes [2]	408			89,119		(90,901)

Data Sources:
1. TEP Income - Payroll Expense workpaper.
2. TEP Income - Payroll Tax Expense workpaper.
Note: TEP's Income - Payroll Expense workpaper identifies FERC Account 930 payroll expense as "General Advertising Exp" (Account 930.1).
However, TEP's revenue requirement model places this adjustment in Account 930.2, Misc. General Expenses. AECC's adjustment is made to Account 930.2.

AECC
Payroll Expense Adjustment Derivation
Test Year Ended June 30, 2015

Line No.		Wages Charged to O&M: Total Payroll	Wages Charged to O&M: Clearing Account Allocations to O&M	Wages Charged to O&M: Deduct SGS Unit 1 - External owners	Exclude A&G Payroll Capitalized through A&G Loader	Deduct SGS Unit 3 Wages	Deduct SGS Unit 4 Wages	Total O&M Wages
1	**Jun-14**	74,298,455	15,808,352	(3,385,007)	(5,289,752)	(7,789,279)	(7,134,089)	66,508,680
2	**Jun-15**	76,779,720	17,193,144	(3,365,954)	(6,234,868)	(7,227,233)	(8,518,905)	68,625,903
3		151,078,174	33,001,496	(6,750,962)	(11,524,619)	(15,016,512)	(15,652,994)	135,134,583
4						2 Year Average O&M Wages		67,567,291
5						Average Wage Rate Increase	2016	2%
6								1,351,346

Data Source: TEP Income - Payroll Expense workpaper.

AECC Payroll Tax Expense Adjustment Derivation

Line No.	TEP Employer Tax - Ended June 2015			
1	Social Security	7,900,994		per Form 941
2	Medicare	2,450,273		per Form 941
3	FUTA/SUTA	143,232		per FUTA and SUTA returns
4		10,494,500		
		Wages, tips and other compensation from Form 941		
5	Q3 2014	62,328,958		
6	Q4 2014	35,209,774		
7	Q1 2015	27,716,883		
8	Q2 2015	33,876,917		
9		159,132,532	0.066	effective tax rate (A)
10	Payroll Adjustment		1,351,346	(B) (from Payroll Expense Adj)
11	Employer Payroll Tax Adjustment		$ 89,119	(A) X (B)
12	TEP Recommended Payroll Tax Adjustment		180,020	

Data Source: TEP Income - Payroll Tax Expense workpaper.

EXHIBIT KCH-9

AECC Short-Term Incentive Compensation Adjustment

Line No.		Total Company AECC Short-Term Incentive Comp. Adjustment ($000) (a)	Jurisdictional AECC Short-Term Incentive Comp. Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(2,484)	(1,773)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	(233)	(195)		15
16	Income Taxes	0	753		16
17	Total Operating Expenses	(2,716)	(1,216)		17
18	Operating Income	2,716	1,216		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,972)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,972)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Short-Term Incentive Compensation Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Taxes Other Than Inc Tax	408	$527,194	$566,200	$333,310	($232,890)
2	Steam Prod Oper Supervision	500	$109,412	$153,796	$90,537	($63,258)
3	Steam Prod Misc Expense	506	$1,283,253	$1,761,093	$1,036,731	($724,362)
4	Steam Prod Mnt Elec Plnt	514	$498,759	$668,144	$393,324	($274,820)
5	Trans Misc Oper Expense	566	$751,760	$1,147,303	$675,415	($471,888)
6	Trans Maint Stn Equip	570	$59,125	$98,181	$57,800	($40,381)
7	Dist Oper Supv & Engr	580	$0	$2,298	$1,354	($945)
8	Dist Misc Expense	588	$370,190	$444,714	$261,788	($182,926)
9	Dist Maint Misc Plant	598	$93,479	$113,025	$66,534	($46,491)
10	Cust Rec/Collection Exp	903	$197,685	$295,032	$173,687	($121,345)
11	A&G Salaries	920	$3,038,685	$2,866,556	$2,309,451	($557,105)
12	Total		$6,929,542	$8,116,343	$5,399,931	($2,716,411)

1. Data Sources: TEP Income - Short Term Incentive Compensation workpaper and TEP Income - Short Term Incentive Compensation - Revised workpaper (provided in TEP's April 14, 2016 supplemental response to UDR 1.001). The amount of AECC's adjustment reflects TEP's filed case.

Derivation of AECC's Short-Term Incentive Compensation Adjustment

Line No.	Account	Average of 6/30/14 and 6/30/15 w/o 2017 Escalation	Average of 6/30/14 and 6/30/15 w/o 2017 Escalation 60%	7/1/14-6/30/15 Unadjusted	TEP Adjustments - Originally-Filed	Adjusted TEP Expenses- Originally-Filed	AECC Adjustment
1	408	555,516	333,310	527,194	39,006	566,200	(232,890)
2	500	150,896	90,537	109,412	44,384	153,796	(63,258)
3	506	1,727,885	1,036,731	1,283,253	477,840	1,761,093	(724,362)
4	514	655,540	393,324	498,759	169,385	668,144	(274,820)
5	566	1,125,691	675,415	751,760	395,543	1,147,303	(471,888)
6	570	96,334	57,800	59,125	39,056	98,181	(40,381)
7	580	2,256	1,354	-	2,298	2,298	(945)
8	588	436,313	261,788	370,190	74,524	444,714	(182,926)
9	598	110,890	66,534	93,479	19,546	113,025	(46,491)
10	903	289,479	173,687	197,685	97,347	295,032	(121,345)
11	920-Net	3,849,086	2,309,451	3,038,685	(172,129)	2,866,556	(557,105)
12	Total	8,999,886	5,399,931	6,929,542	1,186,800	8,116,343	(2,716,411)

Data Sources: TEP's Income - Short Term Incentive Compensation workpaper;
Income - Short Term Incentive Compensation - Revised workpaper.

EXHIBIT KCH-10

AECC Long-Term Incentive Compensation Adjustment

Line No.		Total Company: AECC Long-Term Incentive Comp. Adjustment ($000) (a)	Jurisdictional: AECC Long-Term Incentive Comp. Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,542)	(1,294)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	495		16
17	Total Operating Expenses	(1,542)	(799)		17
18	Operating Income	1,542	799		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,296)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(1,296)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Long-Term Incentive Compensation Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Administrative & General Salaries	920	$491,910	$1,541,834	$0	($1,541,834)

1. Data Source: TEP Income - Long Term Incentive Compensation workpaper.
TEP has provided a correction in Income - Long Term Incentive Compensation - Revised in its March 18, 2016 supplemental response to UDR 1.001. The amount of AECC's adjustment reflects TEP's filed case.

EXHIBIT KCH-11

AECC SERP Adjustment

Line No.		Total Company AECC SERP Adjustment ($000) (a)	Jurisdictional AECC SERP Adjustment ($000) (b)		Line No.
1	**Operating Revenues**				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	**Operating Expenses**				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,130)	(948)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	363		16
17	Total Operating Expenses	(1,130)	(585)		17
18	Operating Income	1,130	585		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(950)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 29 + Ln. 30)		$\boxed{(950)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC SERP Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Pensions & Benefits	926	$564,903	$1,129,807	$0	($1,129,807)

1. Data Source: TEP Income - Pension_Benefits workpaper.

EXHIBIT KCH-12

AECC Severance Expense Adjustment

Line No.		Total Company: AECC Severance Expense Adjustment ($000) (a)	Jurisdictional: AECC Severance Expense Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(254)	(218)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	83		16
17	Total Operating Expenses	(254)	(135)		17
18	Operating Income	254	135		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(218)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(218)}$		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Severance Expense Adjustment

			AECC Recommended			TEP Proposed[1]			AECC Adjustment		
Line No.	Description	FERC Acct	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Distribution O&M Expenses										
2	Operation Supervision & Engineering	580	$0	100.0%	$0	$30,000	100.0%	$30,000	($30,000)	100.0%	($30,000)
3	Administrative & General Expenses										
4	A&G Salaries	920	$0	83.9%	$0	$223,853	83.9%	$187,830	($223,853)	83.9%	($187,830)
5	Total Adjustment		$0		$0	$253,853		$217,830	($253,853)		($217,830)

1. Data Source: TEP Response to Uniform Data Request No. 1.043.

EXHIBIT KCH-13

AECC Credit Card Processing Fees Adjustment

Line No.		Total Company AECC Credit Card Processing Fees Adjustment ($000) (a)	Jurisdictional AECC Credit Card Processing Fees Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(3,476)	(3,476)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	1,329		16
17	Total Operating Expenses	(3,476)	(2,146)		17
18	Operating Income	3,476	2,146		18
19	Rate Base - Original Cost	0	0		19
20	Rate Base - RCND	0	0		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(3,482)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		0		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(3,482)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Credit Card Processing Fees Adjustment

Line No.	Description	FERC Account	Unadjusted Total Company Test Year Amount[1]	TEP Proposed Total Company Test Year Amount[1]	AECC Recommended Total Company Test Year Amount	AECC Recommended Total Company Adjustment
1	Customer Records & Collection Expenses	903	$0	$3,475,500	$0	($3,475,500)

1. Data Source: TEP Income - Credit Card Processing Fees workpaper.
TEP has provided a correction in Income - Credit Card Processing Fees-Revised in its April 14, 2016 supplemental response to UDR 1.001.
The amount of AECC's adjustment reflects TEP's filed case.

EXHIBIT KCH-14

AECC Generation Overhaul Expense Adjustment

Line No.		Total Company AECC Generation Overhaul Expense Adjustment ($000) (a)	Jurisdictional AECC Generation Overhaul Expense Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	(1,946)	(1,862)		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	712		16
17	Total Operating Expenses	(1,946)	(1,150)		17
18	Operating Income	1,946	1,150		18
19	Rate Base - Original Cost	0	(0)		19
20	Rate Base - RCND	0	(0)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(1,865)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x TEP WACC x Ln. 21)		(0)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		$\boxed{(1,865)}$		25

<u>Supporting Schedules/Data Source</u>
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

AECC Normalized Generation Overhaul Expense Adjustment

Generation Overhaul Expense by Plant

			AECC Recommended			TEP Proposed[2]			AECC Adjustment		
Line No.	Plant	Test Year Total Company Actual[1]	Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	TEP Total Company Amount	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount	AECC Recommended Adjustment	ACC Jurisdictional Allocation Percent	ACC Jurisdictional Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Four Corners	$0	$854,175	95.66%	$817,092	$2,700,063	95.66%	$2,582,841	($1,845,888)	95.66%	($1,765,750)
2	Navajo	$2,561,527	$1,902,764	95.66%	$1,820,156	$1,384,559	95.66%	$1,324,449	$518,205	95.66%	$495,707
3	San Juan	$4,464,000	$1,488,000	95.66%	$1,423,400	$2,188,235	95.66%	$2,093,235	($700,235)	95.66%	($669,835)
4	Luna	$1,185,383	$1,409,192	95.66%	$1,348,013	$944,201	95.66%	$903,209	$464,991	95.66%	$444,804
5	Gila	$232,778	$620,695	95.66%	$593,748	$641,176	95.66%	$613,340	($20,482)	95.66%	($19,593)
6	Springerville	$0	$3,735,385	95.66%	$3,573,216	$3,419,588	95.66%	$3,271,129	$315,797	95.66%	$302,087
7	Sundt/Irvington	$0	$1,223,299	95.66%	$1,170,190	$ 1,582,059	95.66%	$1,513,375	($358,760)	95.66%	($343,185)
8	ICT	$0	$306,432	95.66%	$293,128	$626,471	95.66%	$599,273	($320,039)	95.66%	($306,145)
9	Total Expense (Acct 512)	$8,443,688	$11,539,941		$11,038,943	$13,486,351		$12,900,852	($1,946,411)		($1,861,909)

1. TEP's direct filing workpapers used 2015 budget numbers (Total = $8,074,926) as the basis for its adjustments. The amounts shown in Column (b) have been adjusted to reflect 2015 actual expenses.
2. Data Source: TEP As-Filed Pro Forma Income - Overhaul_Outage Normalization Workpaper.

EXHIBIT KCH-15

AECC Return on Equity Adjustment

Line No.		Total Company: AECC Capital Structure Adjustment (a)	Jurisdictional: AECC Incentive Compensation Adjustment (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	0	0		2
3	PPFAC Revenue	0	0		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	0	0		6
7	Operating Expenses				7
8	Fuel Expense	0	0		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	0	0		12
13	Other Operations & Maintenance Expense	0	0		13
14	Depreciation and Amortization	0	0		14
15	Taxes Other than Income	0	0		15
16	Income Taxes	0	0		16
17	Total Operating Expenses	0	0		17
18	Operating Income	0	0		18
19	Rate Base - Original Cost	0	0		19
20	Rate Base - RCND	0	0		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		0		22
23	TEP As-Filed OCRB Rate Base (KCH-1, p. 2, Ln. 1)		2,104,678		23
24	Total AECC OCRB Rate Base Adjustments before ROE Adjustment		(52,619)		24
25	Total Adjusted OCRB Rate Base before ROE Adjustment (Ln. 23 + Ln. 24)		2,052,059		25
26	Weighted Cost of Capital before AECC ROE Adjustment		7.34%		26
27	Total Adjusted OCRB Rate Base after ROE Adjustment (Ln. 19 + Ln. 25)		2,052,059		27
28	Weighted Cost of Capital after AECC ROE Adjustment		7.01%		28
29	OCRB Revenue Req't Impact ([(Ln. 27 x Ln. 28) - (Ln. 25 x Ln. 26)] x Ln. 21)		(10,826)		29
30	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		0		30
31	Total Revenue Requirement Impact (Ln. 22 + Ln. 29 + Ln. 30)		$\boxed{(10,826)}$		31

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

2012 Vertically-Integrated Electric Utility Rate Case Summary
Cases with ROE Determinations as Reported by SNL Financial

Decision Date	State	Company	Case Identification	Common Equity /Total Cap (%)	Return on Equity (%)
1/25/2012	South Carolina	Duke Energy Carolinas LLC	D-2011-271-E	53.00	**10.50**
1/27/2012	North Carolina	Duke Energy Carolinas LLC	D-E-7, Sub 989	53.00	**10.50**
2/15/2012	Michigan	Indiana Michigan Power Co.	C-U-16801	42.07	**10.20**
2/23/2012	Oregon	Idaho Power Co.	D-UE-233	49.90	**9.90**
2/27/2012	Florida	Gulf Power Co.	D-110138-EI	38.50	**10.25**
2/29/2012	North Dakota	Northern States Power Co. - MN	C-PU-10-657	NA	**10.40**
3/29/2012	Minnesota	Northern States Power Co. - MN	D-E-002/GR-10-971	52.56	**10.37**
4/4/2012	Hawaii	Hawaii Electric Light Co	D-2009-0164	55.91	**10.00**
4/26/2012	Colorado	Public Service Co. of CO	D-11AL-947E	56.00	**10.00**
5/2/2012	Hawaii	Maui Electric Company Ltd	D-2009-0163	56.86	**10.00**
5/7/2012	Washington	Puget Sound Energy Inc.	D-UE-111048	48.00	**9.80**
5/15/2012	Arizona	Arizona Public Service Co.	D-E-01345A-11-0224	53.94	**10.00**
6/7/2012	Michigan	Consumers Energy Co.	C-U-16794	42.07	**10.30**
6/15/2012	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-118 (elec)	49.31	**10.40**
6/18/2012	Wyoming	Cheyenne Light Fuel Power Co.	D-20003-114-ER-11 (elec)	54.00	**9.60**
6/19/2012	South Dakota	Northern States Power Co. - MN	D-EL11-019	53.04	**9.25**
6/26/2012	Michigan	Wisconsin Electric Power Co.	C-U-16830	43.51	**10.10**
6/29/2012	Hawaii	Hawaiian Electric Co.	D-2010-0080	56.29	**10.00**
7/9/2012	Oklahoma	Oklahoma Gas and Electric Co.	Ca-PUD201100087	NA	**10.20**
7/16/2012	Wyoming	PacifiCorp	D-20000-405-ER-11	52.10	**9.80**
9/13/2012	Texas	Entergy Texas Inc.	D-39896	49.92	**9.80**
9/19/2012	Utah	PacifiCorp	D-11-035-200	52.10	**9.80**
10/24/2012	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-121 (Elec)	51.61	**10.30**
11/9/2012	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-118 (elec)	59.09	**10.30**
11/28/2012	Wisconsin	Wisconsin Electric Power Co.	D-05-UR-106 (WEP-Elec)	52.09	**10.40**
11/29/2012	California	Liberty Utilities CalPeco Ele	A-12-02-014	51.50	**9.88**
12/12/2012	Missouri	Union Electric Co.	C-ER-2012-0166	52.30	**9.80**
12/13/2012	Florida	Florida Power & Light Co.	D-120015-EI	NA	**10.50**
12/13/2012	Kansas	Kansas City Power & Light	D-12-KCPE-764-RTS	51.82	**9.50**
12/14/2012	Wisconsin	Northern States Power Co - WI	D-4220-UR-118 (elec)	52.37	**10.40**
12/19/2012	South Carolina	South Carolina Electric & Gas	D-2012-218-E	52.18	**10.25**
12/20/2012	California	Southern California Edison Co.	Ap-12-04-015	48.00	**10.45**
12/20/2012	California	San Diego Gas & Electric Co.	Ap-12-04-016 (Elec)	52.00	**10.30**
12/20/2012	California	Pacific Gas and Electric Co.	Ap-12-04-018 (Elec)	52.00	**10.40**
12/20/2012	Kentucky	Kentucky Utilities Co.	C-2012-00221	NA	**10.25**
12/20/2012	Kentucky	Louisville Gas & Electric Co.	C-2012-00222 (elec.)	NA	**10.25**
12/20/2012	Oregon	PacifiCorp	D-UE-246	52.10	**9.80**
12/21/2012	North Carolina	Virginia Electric & Power Co.	D-E-22, Sub 479	51.00	**10.20**
12/26/2012	Washington	Avista Corp.	D-UE-120436	47.00	**9.80**
			MEDIAN:	52.10	**10.20**
			OBSERVATIONS:	34	39

2015 - Q1 2016 Vertically-Integrated Electric Utility Rate Case Summary
Cases with ROE Determinations as Reported by SNL Financial

Decision Date	State	Company	Case Identification	Common Equity /Total Cap (%)	Return on Equity (%)
1/23/2015	Wyoming	PacifiCorp	D-20000-446-ER-14	51.43	**9.50**
2/24/2015	Colorado	Public Service Co. of CO	D-14AL-0660E	56.00	**9.83**
3/25/2015	Washington	PacifiCorp	D-UE-140762	49.10	**9.50**
3/26/2015	Minnesota	Northern States Power Co. - MN	D-E-002/GR-13-868	52.50	**9.72**
4/23/2015	Michigan	Wisconsin Public Service Corp.	C-U-17669	NA	**10.20**
4/29/2015	Missouri	Union Electric Co.	C-ER-2014-0258	51.76	**9.53**
5/26/2015	West Virginia	Appalachian Power Co.	C-14-1152-E-42T	47.16	**9.75**
9/2/2015	Missouri	Kansas City Power & Light	C-ER-2014-0370	50.09	**9.50**
9/10/2015	Kansas	Kansas City Power & Light	D-15-KCPE-116-RTS	50.48	**9.30**
11/19/2015	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-124 (Elec)	50.47	**10.00**
11/19/2015	Michigan	Consumers Energy Co.	C-U-17735	41.50	**10.30**
12/3/2015	Wisconsin	Northern States Power Co - WI	D-4220-UR-121 (Elec)	52.49	**10.00**
12/11/2015	Michigan	DTE Electric Co.	C-U-17767	38.03	**10.30**
12/15/2015	Oregon	Portland General Electric Co.	D-UE-294	50.00	**9.60**
12/17/2015	Texas	Southwestern Public Service Co	D-43695	51.00	**9.70**
12/18/2015	Idaho	Avista Corp.	C-AVU-E-15-05	50.00	**9.50**
12/30/2015	Wyoming	PacifiCorp	D-20000-469-ER-15	51.44	**9.50**
1/6/2016	Washington	Avista Corp.	D-UE-150204	48.5	**9.5**
2/23/2016	Arkansas	Entergy Arkansas Inc.	D-15-015-U	28.46	**9.75**
3/16/2016	Indiana	Indianapolis Power & Light Co.	Ca-44576	37.33	**9.85**
			MEDIAN:	50.09	**9.71**
			OBSERVATIONS:	19	20

EXHIBIT KCH-16

Page 2 CONFIDENTIAL

AECC Jurisdictional Allocation Adjustment

Line No.		Total Company AECC Jurisdictional Allocation Adjustment ($000) (a)	Jurisdictional AECC Jurisdictional Allocation Adjustment ($000) (b)		Line No.
1	Operating Revenues				1
2	Electric Retail Non-Fuel Revenue	(2,715)	(2,715)		2
3	PPFAC Revenue	2,715	2,715		3
4	Sales for Resale	0	0		4
5	Other Operating Revenue	0	0		5
6	Total Operating Revenues	(0)	0		6
7	Operating Expenses				7
8	Fuel Expense	2,715	2,715		8
9	Purchased Power - Demand	0	0		9
10	Purchased Power - Energy	0	0		10
11	Transmission	0	0		11
12	Fuel, Purchased Power and Transmission	2,715	2,715		12
13	Other Operations & Maintenance Expense	0	(4,944)		13
14	Depreciation and Amortization	0	(4,248)		14
15	Taxes Other than Income	0	(748)		15
16	Income Taxes	0	3,265		16
17	Total Operating Expenses	2,715	(3,960)		17
18	Operating Income	(2,715)	3,960		18
19	Rate Base - Original Cost	0	(62,117)		19
20	Rate Base - RCND	0	(110,196)		20
21	Gross Revenue Conversion Factor		1.6223	(c)	21
22	Operating Income Revenue Requirement Impact (-Ln. 18 x Ln. 21)		(6,424)		22
23	OCRB Revenue Requirement Impact (Ln. 19 x AECC WACC x Ln. 21)		(7,066)		23
24	FV Increment Rev. Req't Impact (Avg[Ln. 19, Ln. 20] - Ln. 19 x 1.42% x Ln. 21)		(554)		24
25	Total Revenue Requirement Impact (Ln. 22 + Ln. 23 + Ln. 24)		(14,043)		25

Supporting Schedules/Data Source
(a) & (b) TEP Rev Req Model - AECC WP
(c) TEP Schedule C-3

Derivation of AECC's Recommended Demand Jurisdictional Allocation Factor

DEMAND ALLOCATON - 2015

Line No.	Date	Retail System Peak	SRP	NTUA	TOUA	Shell	Trico	Sub-Total FERC	FERC w/SRP Removed	Total	Line No.
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = Sum(b:f)	(h) = (g) -(b)	(i) = (a) + (j)	
1	June, 2015										1
2	July, 2015				CONFIDENTIAL						2
3	August, 2015										3
4	September, 2015										4
5	Total										5
6	Average (Line 5/ 4)										6
7	Demand Allocation Factor (Line 6 - (a)/(i) and (h)/(i)	91.53%							8.47%	100.00%	7

EXHIBIT KCH-17

AECC New Corporate Headquarters Building Return Adjustment

Line No.	Description	FERC Account	ACC Jurisdiction Test Year Net Book Value[1]	ACC Jurisdiction Return at TEP Proposed WACC[2] 7.34%	ACC Jurisdiction Return at TEP TY Average Cost of Debt[3] 4.32%	ACC Jurisdiction Headquarters Return Adjustment -3.0145%
1	Land	389	7,521,380	551,829	325,098	(226,731)
2	Structures & Improvements	390	60,140,795	4,412,415	2,599,476	(1,812,939)
3	Furniture & Equipment	391	1,162,146	85,264	50,232	(35,033)
4	Network Equipment	391	3,139,038	230,305	135,679	(94,626)
5	Communication Equip	397	628,171	46,088	27,152	(18,936)
6	Miscellaneous Equipment	398	36,468	2,676	1,576	(1,099)
7	Total		72,627,999	5,328,578	3,139,213	(2,189,365)

8	ACC Jurisdiction Return Adjustment	($2,189,365)
9	Gross Revenue Conversion Factor[4]	1.6223
10	Revenue Requirement Impact	($3,551,835)

1. Data Source: TEP's Response to AECC 15.1.
2. Data Source: TEP recommended WACC, see Schedule D-1, p. 1 of 2.
3. Data Source: TEP TY recommended cost of debt based on the average of TEP's cost of long term debt as reported in TEP Schedule D-2, p. 1 of 2.
4. Data Source: TEP recommended WACC, see Schedule C-3, p. 1 of 1.

EXHIBIT KCH-18

Exhibit KCH-18

TEP's Non-Confidential Responses
To Parties' Data Requests
Referenced in Testimony & Exhibits

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 January 14, 2016

AECC 1.3

Bonus tax depreciation. Using TEP's direct case as a starting point, what is the impact on the TEP's revenue requirement resulting from the five year extension of bonus tax depreciation in H.R. 2029 (as signed into law by President Obama on December 18, 2015)? Please provide the adjustments necessary on both a Total Company and ACC Jurisdictional basis necessary to reflect the impact of this extension on TEP's requested revenue increase. Please provide the workpapers used to support this response in Excel format with formulas intact.

RESPONSE: January 4, 2016

TEP is in the process of evaluating the H.R. 2029 through its year end close process and will respond as soon as possible.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: January 14, 2016

For an updated Accumulated Deferred Income Tax pro forma adjustment that includes the impacts of the extension of bonus depreciation, see AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes.xlsm. This update would reduce the overall revenue requirement by approximately $1.5 million. The Excel file is not identified by Bates numbers.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

Tucson Electric Power Company
RATE BASE PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2015

ADJUSTMENT NAME:	Accumulated Deferred Income Taxes
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	January 13, 2016
PREPARED BY:	Donye' Bonsu
CHECKED BY:	
REVIEWED BY:	Jay Rademacher

		Total Company		ACC Jurisdictional	
FERC ACCT	**FERC ACCOUNT DESCRIPTION**	**DEBIT**	**CREDIT**	**DEBIT**	**CREDIT**
190	ADIT	-	168,923,600		$136,246,714
282	ADIT - Other Property	19,241,437	-	$15,519,338	
283	ADIT - Other	51,043,022	-	$49,604,518	
	ENTRY TOTAL	**$70,284,459**	**$168,923,600**	**$65,123,856**	**$136,246,714**
	NET ENTRY		**$98,639,141**		**$71,122,858**

Reason for Adjustment

To adjust rate base to reflect the pro forma test year ADIT.

AECC 7.5

Please refer to STF 3.3 Jurisdictional Allocation-Confidential, provided in TEP's response to Staff Data Request 3.3, the "Demand Summary" tab.

a. Please explain why the SRP and Shell demand has been removed in the calculation of the jurisdictional demand allocation factors.

b. Please provide the expiration dates of the SRP and Shell wholesale contracts.

RESPONSE:

a.-b. The SRP and Shell wholesale contract will expire May 31, 2016 and December 31, 2017 respectively. New Rates will not become effected until the first part of 2017; therefore, the demand allocation proposed by the company reflects the appropriate known and measurable long term Wholesale demand levels.

RESPONDENT:

David Lewis

WITNESS:

Craig Jones

AECC 10.1

Legal expenses.

a. Please identify by FERC account the amount of outside legal expense included in the test year retail revenue requirement.

b. Are there any differences between TEP's per-books outside legal expense and the amount included in the test year retail revenue requirement? If so, please show where these adjustments are presented in TEP's filing.

c. Please identify by FERC account the amount of outside legal expense included in TEP's requested test year retail revenue requirement in Docket No. E-01993A-12-0291.

d. Please identify by FERC account the amount of outside legal expense incurred by TEP in each of the following years: 2012, 2013, and 2014.

e. Please refer to the Direct Testimony of Michael E. Sheehan, p. 45, lines 18-19. Are any of the outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1 included in the test year retail revenue requirement? If so, please identify this amount, indicate the docket number(s) of the cases, and explain the rationale for recovering these expenses from ratepayers.

RESPONSE: **April 18, 2016**

a. Please see AECC 10.1a Legal Expenses.xlxs. The Excel file is not identified by Bates numbers.

b. The differences between TEP's books outside legal expense and the amount included in the test year are identified in the file referenced in AECC 10.1a.

c. Please see AECC 10.1c Legal Expenses.xlxs. The Excel file is not identified by Bates numbers.

d. Please see AECC 10.1d Legal Expenses.xlxs. The Excel file is not identified by Bates numbers.

e Yes. There is $1,340,437 of outside legal expenses associated with the co-owners and former lessors of Springerville Unit 1 included in the test year retail revenue requirement. Below is a list of the case numbers and docket number:

Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade v. TEP
FERC Dkt. No. EL15-17-000

Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade v. TEP
Case No. 653898/2014
New York County Supreme Court

Alterna Springerville LLC, LDVF1 TEP LLC (via Wilmington Trust Company and William J. Wade as Trustees)
Case No. 01-15-0003-7373
American Arbitration Association

TEP v. Alterna Springerville LLC, LDVF1 TEP LLC, Wilmington Trust Co. and William J. Wade Consolidated Matter
Case No. 01-15-0003-2729
American Arbitration Association New York

The rationale for recovery is that these legal expenses were necessary in order to acquire the interests in SGS Unit 1. As such, they are considered transaction costs for the acquisition to provide service to customers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: May 13, 2016

In response to AECC 19.1, TEP provides the following. The legal expenses shown in AECC 10.1d Legal Expenses.xlxs are on a total Company basis. For the ACC jurisdictional basis, please see AECC 10.1d Legal Expenses ACC Basis.xlsx. The Excel file is not identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Dallas Dukes

Tucson Electric Power
Legal Expenses
AECC 10.1a

FERC	Test Year Unadjusted Balance	REST & DSM Adjustment	Springerville Units 3 & 4	Power Supply Management	Test Year Adjusted Balance
0500	1,115.00	-	-	-	1,115.00
0502	-	-	-	-	-
0506	4,789.50	-	(2,394.72)	-	2,394.78
0556	-	-	-	-	-
0560	203.50	-	-	-	203.50
0590	-	-	-	-	-
0903	31,346.36	-	-	-	31,346.36
0908	16,945.95	-	-	-	16,945.95
0923	3,483,179.46	(357,949.73)	-	(22,619.00)	3,102,610.73
0926	101,041.56	-	-	-	101,041.56
	3,638,621.33	(357,949.73)	(2,394.72)	(22,619.00)	3,255,657.88

Tucson Electric Power
Legal Expenses
AECC 10.1c

FERC	Unadjusted Calendar Yr. 2011	REST & DSM	Springerville Units 3 & 4	Adjusted Calendar Yr. 2011
0417	(8,323.10)	-	8,323.10	-
0514	76,822.13	-	-	76,822.13
0556	5,410.85	-	-	5,410.85
0903	20,117.18	-	-	20,117.18
0908	1,849.00	-	-	1,849.00
0923	1,925,765.71	(58,051.48)	(4,161.54)	1,863,552.69
0926	320,820.19	-		320,820.19
	2,342,461.96	(58,051.48)	4,161.56	2,288,572.04

Tucson Electric Power
Legal Expenses
AECC 10.1d

FERC	DEC-12	Test Year Ended June 30, 2015 ACC %	ACC Jurisdiction Basis DEC-12
0500	-	89.782780%	-
0502	28,676.25	89.782780%	25,746.33
0506	-	89.782780%	-
0556	3,382.00	-	-
0560	560.00	-	-
0590	-	100.000000%	-
0903	32,374.88	100.000000%	32,374.88
0908	117,158.21	100.000000%	117,158.21
0923	1,672,679.97	83.907730%	1,403,507.79
0926	48,438.70	83.907730%	40,643.81
	1,903,270.01		1,619,431.02

FERC	DEC-13	Test Year Ended June 30, 2015 ACC %	ACC Jurisdiction Basis DEC-13
0500	12,636.25	89.782780%	11,345.18
0502	-	89.782780%	-
0506	-	89.782780%	-
0556	72.00	-	-
0560	17,828.92	-	-
0590	777.00	100.000000%	777.00
0903	27,586.75	100.000000%	27,586.75
0908	11,708.51	100.000000%	11,708.51
0923	1,445,192.93	83.907730%	1,212,628.58
0926	185,733.53	83.907730%	155,844.79
	1,701,535.89		1,419,890.81

FERC	DEC-14	Test Year Ended June 30, 2015 ACC %	ACC Jurisdiction Basis DEC-13
0500	62,575.08	89.782780%	56,181.65
0502	-	89.782780%	-
0506	4,789.50	89.782780%	4,300.15
0556	-	-	-
0560	869.50	-	-
0590	-	100.000000%	-
0903	36,146.66	100.000000%	36,146.66
0908	14,523.00	100.000000%	14,523.00
0923	2,279,615.48	83.907730%	1,912,773.60
0926	236,822.27	83.907730%	198,712.19
	2,635,341.49		2,222,637.25

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 14, 2016

AECC 11.3

Please refer to the Direct Testimony of Kentton C. Grant, pp. 31-32. Regarding TEP's proposal to include $42.7 million of the 2006 SGS 1 acquisition in rate base:

a. Please explain the current accounting treatment on TEP's books of this $42.7 million, as well as the original $48 million acquisition cost.

b. Has any portion of this acquisition cost been amortized? If so, please explain and identify the amortization schedule.

c. Has TEP requested to include any portion of the 2006 acquisition investment in a prior rate case? If yes, please explain. If not, please explain why TEP has not requested inclusion in rate base previously.

d. What is the net book value of SGS 1 on January 2, 2015 (when TEP completed the purchase)? Please separately identify original cost, capital improvements, and accumulated depreciation. What was the net book value of the SGS Coal Handling Facility on June 30, 2015 (at the end of the test year)? Please separately identify original cost, capital improvements, and accumulated depreciation.

e. What was the net book value of the SGS 1 on June 30, 2015 (at the end of the test year)? Please separately identify original cost, capital improvements, and accumulated depreciation.

f. What is the amount of ADIT for the SGS 1 on June 30, 2015?

RESPONSE:

a. TEP's current accounting reflects $36 million of net assets as discussed in part b of this response. These assets are currently accounted for as a component of the plant in service and accumulated depreciation accounts.

b. The original $48 million lease asset acquisition was treated as a lease equity investment and was amortized to $36 million as of December 31, 2014.

c. No. TEP has not previously requested rate base treatment of the referenced lease equity investment since SGS Unit 1 was reflected in rates as an operating lease expense. As described in Mr. Grant's direct testimony, when TEP purchased the lease equity interest, it paid for the right to receive all of the remaining lease equity rents, as well as for the residual value of the asset at the end of the lease. Now that the lease term has ended, TEP is seeking to include a portion of the original lease equity investment in rate base as a cost of acquiring the asset. However, the portion of the original lease equity investment requested in rate base is higher, on a percentage basis, than the portion requested for the SGS coal handling facilities. That is because the reduction in lease equity rents achieved by TEP, when it amended the lease in 2006, was fully reflected in the SGS Unit 1 revenue requirement in the 2008 rate order.

d.-f. See AECC 11.2 and 11.3 SGS NBV and ADIT.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Rigo Ramirez / Jason Rademacher

WITNESS:

Kentton Grant / Dallas Dukes

Tucson Electric Power Company
Rate Case Test Year Ended 06/30/2015
AECC 11.2 & 11.3 SGS1 and SGSCH Net Book Value & ADIT

Springerville Unit 1

	1/2/2015	6/30/2015
Plant in Service - Account 101	358,470,749	359,418,280
Accumulated Reserve - Account 108	(168,658,726)	(171,271,606)
Acquisition Adjustment - Account 114	(40,636,573)	(40,636,573)
Amortization of Acq. Adj. Account 115	-	655,926
Net Book Value	149,175,450	148,166,027
ADIT		(9,892,156)

Springerville Coal Handling*

	4/5/2015	6/30/2015
Plant in Service - Account 101	206,670,828	179,094,730
Accumulated Reserve - Account 108	(90,824,298)	(78,367,861)
Acquisition Adjustment - Account 114	24,700,725	18,445,964
Amortization of Acq. Adj. Account 115	-	(84,828)
Net Book Value	140,547,255	119,088,005
ADIT		(4,327,551)

*The amounts include coal handling related rolling stock which is not associated with the Springerville Coal Handling Facility lease.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC FIFTEENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 03, 2016

AECC 15.1

Follow up to TEP's response to AECC Data Request 11.4. In response to AECC Data Request No. 11.4, TEP provided the costs of its new headquarters building included in rate base in the current rate case. As a follow-up, please provide the following:

a. Please provide a breakdown of the amounts shown for the new TEP headquarters in 11.4(b) by FERC account. In addition, please include both the Total Company and the ACC jurisdictional allocation for each FERC account amount.

b. Please provide a description of the $3.3 million capital improvements that were necessary on the new TEP headquarters building.

c. Please provide the Total Company amounts by FERC account (both cost and accumulated depreciation) that TEP included in its last rate case (Docket No. E-01933A-12-0291) for the new headquarters building.

d. Please reconcile any differences in the Total Company headquarters original cost amount provided in TEP's response to 11.4 with the headquarters gross rate base included in TEP's ast rate case, Docket No. E-01933A-12-029. (See TEP's responses to AECC Data Requests 9.1 and 11.8 in that docket.) If the headquarters' original cost has increased since the last rate case, please provide an explanation for the increase.

RESPONSE:

a. The amounts provided below reflect the response to RUCO 7.20a. AECC 11.4a was prepared based on information using TEP's Utility Plant report. However, subsequent to AECC 11.4a information related to the headquarters building was updated for the response to RUCO 7.20a. The amounts reflect changes for the removal of end user computer equipment (391-CP) such as PC's, laptops and I-pads, also (303-software) was removed. After further consideration these type of assets should not be directly attributable to the building but rather stand-alone in nature. Please see tabs labeled "AECC 15.1a Part 1" for rate base and "AECC 15.1a Part 2" for ACC Jurisdictional in AECC 15.1 Support.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

b. The $3.3 million capital improvements provided in response to AECC 11.4a have been removed from the response to RUCO 7.20a. The capital improvements included leasehold improvements related to the old leased downtown building, these are not part of the new headquarters building and have also subsequently been fully amortized and retired from plant in-service in September 2015.

c. Please see attached file AECC 15.1 2012 TEP RC DR AECC 9.1 and 9.2.pdf, Bates Nos. TEP\024256-024257, for New HQ Building cost and accumulated depreciation included in the last rate case.

d. The increase of $3.9M since the last rate case is due to an addition of a security system, parking lot, network equipment and office furniture. Please see tab labeled "AECC 15.1d" in the attached excel file "AECC 15.1 Support.xlsx". The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Chrissy Cuevas (a part 1, b, d)/ Bernadette Porter (a part 2, c.)

WITNESS:

Dallas Dukes / Frank Marino

Tucson Electric Power

New Headquarter Building

AECC 15.1a Part 1

Ferc	Description	Original Cost	Accumulated Depreciation	Balance at June 30, 2015
E389	Land	8,549,937.60	0.00	8,549,937.60
E390	Structures & Improvements	72,957,362.70	4,585,467.09	68,371,895.61
E391	Furniture & Equipment	8,559,226.70	7,227,474.81	1,331,751.89
E391	Network Equipment	7,689,575.44	4,115,188.73	3,574,386.71
E397	Communication Equip	873,133.72	158,825.40	714,308.32
E398	Miscellaneous Equipment	50,023.47	8,555.31	41,468.16
Total		**98,679,259.63**	**16,095,511.35**	**82,583,748.28**

Tucson Electric Power
New Headquarter Building
AECC 15.1a Part 2

		ACC Jurisdictional				
Ferc	Description	ACC Jurisdiction Rate	ACC Jurisdiction Cost	ACC Jurisdiction Rate	ACC Jurisdiction Accumulated Deprn	ACC Net Book Value
E389	Land	87.97%	7,521,380.11	88.10%	-	7,521,380.11
E390	Structures & Improvements	87.97%	64,180,591.97	88.10%	4,039,796.51	60,140,795.46
E391	Furniture & Equipment	87.97%	7,529,551.73	88.10%	6,367,405.31	1,162,146.42
E391	Network Equipment	87.97%	6,764,519.51	88.10%	3,625,481.27	3,139,038.24
E397	Communication Equip	87.97%	768,095.73	88.10%	139,925.18	628,170.55
E398	Miscellaneous Equipment	87.97%	44,005.65	88.10%	7,537.23	36,468.42
Total			86,808,144.70		14,180,145.50	72,627,999.20

AECC 16.1

Please refer to Schedule B-2, p. 4.

a. Does the $25,112 (thousand) regulatory asset entry in the "SGS CHF" column include the $23,886,510 regulatory asset being requested by TEP for the share of leasehold improvements attributed to the 50.5% Springerville Unit 1 owner (as identified in Attachment AECC 10.2 SGS U1 LH Improvements 50.5)?

b. If so, why is this regulatory asset classified in Schedule B-2 as being related to the coal handling facility?

c. Please identify the annual ACC jurisdictional revenue requirement being requested for the $23,886,510 regulatory asset, separately identifying return and amortization expense. Please provide the proposed amortization schedule and indicate where in TEP's filing the amortization expense is included or identified.

d. Does the $25,112 (thousand) regulatory asset entry in the "SGS CHF" column include the $1,112 (thousand) "Sundt and San Juan M&S" regulatory asset identified in Schedule B-2, p. 3?

e. If so, why is this regulatory asset classified in Schedule B-2 as being related to the coal handling facility?

f. Please identify the annual ACC jurisdictional revenue requirement being requested for the $1,112 (thousand) "Sundt and San Juan M&S" regulatory asset, separately identifying return and amortization expense. Please provide the proposed amortization schedule and indicate where in TEP's filing the amortization expense is included or identified.

RESPONSE:

a. Yes. As explained in company witness Kent Grant testimony, the leasehold improvements associated with the 50.5% co-owner share were reclassified as a regulatory asset and remain on the same 10-year amortization schedule approved in TEP's last rate case.

b. The column title should have been more inclusive or possibly a new column should have been prepared for the regulatory asset. The regulatory asset entry under the column SGS CHF includes the following:

SGS Unit 1 Leasehold Improvements	$23,886,510
Sundt and San Juan Materials & Supplies	1,225,594
Regulatory Assets	$25,112,104

c. The annual ACC jurisdictional revenue requirement the Company is requesting is $4,688,755. This is made up of $2,165,307 of amortization expense and $2,523,448 or return. The amortization expense is included in the Depreciation and Amortization Expense Annualization pro forma adjustment. Please see attached Regulatory Asset Amortization schedule for additional detail and FERC accounts.

d. See AECC 16.1(b) above.

e. See AECC 16.1(b) above.

f. The annual ACC jurisdictional revenue requirement the Company is requesting is $537,984. This is comprised of $408,531 of amortization expense and $129,423 return. The amortization expense is included in the Sundt and San Juan Material & Supply pro forma adjustment. Please see attached Regulatory Asset Amortization file for additional detail and FERC accounts.

RESPONDENT:

Rigo Ramirez

WITNESS:

Kentton Grant

RUCO 5.1

Credit Card Processing Fees – Please answer the following questions as they relate to Credit Card Processing Fees:

a. In the Company's pro forma adjustment for credit card processing fees, do year 1, year 2, and year 3 refer to 2016, 2017, and 2018? If no, what years do they refer to?

b. In the Company's pro forma adjustment for credit card processing fees, please update the 2015 estimated volume and dollars to actual.

c. In year 1 why does the Company believe credit card usage will increase by 50 percent, 10 percent in year 2, and 10 percent in year 3, or 70 percent overall?

d. Please provide a copy of all contracts between TEP and the credit card vendors.

e. Currently does the Company credit card fee of $3.50 to TEP customers not cover the credit card vendor expenses, TEP has to pay? If no, please provide the amount that is under collected along with the supporting calculations of this amount.

f. How are card paying customers "paying their fair share" if under the Company's proposal non-credit card customers now have to pick-up some of their expenses.

g. How does the Company's proposal not create subsidizes for credit card paying customers at the expense of those that do not pay by credit card?

h. How does the Company's proposal follow cost of service ratemaking (i.e. cost causation)?

i. If the customer has money withdrawn from his/her bank account automatically, does the Company have to pay a fee to the bank?

j. If yes to i., does the Company charge a bank fee to these customers?

RESPONSE:

a. No, they related to 2017, 2018, and 2019.

b. Please refer to the attached Excel file: Income – Credit Card Processing Fees-Revised.xlsm provided in response to UDR 1.001, as supplemented.

c. The increases were based on estimates provided by two independent industry leaders in utility credit card payment processing. It is not a figure calculated by TEP.

According to the research and analysis, utilities who do not charge a convenience fee see double the volume of transactions over those who do charge a fee.

d. The responsive file is competitively sensitive confidential with the ownership of the document held by the contractor. TEP attempted to gain permission to provide the file, but permission was denied.

e. The $3.50 fee represents 100% of the third party transaction costs associated with the credit card payments. The fee is paid directly to the third party vendor by the customer making the payment. TEP does not incur any of these costs.

f. Customers can pay their TEP bill in a number of ways: by check, cash, automatic bank account deduction or credit card. The Company's cost to process these payments varies by type of remittance and its overall processing costs are impacted by customers' behavior. TEP's proposal is in response to consistent feedback from TEP customers indicating dissatisfaction with the high fee that is imposed when paying their bill by credit card. The Company has experienced a growing trend that customers prefer to pay their utility bills by credit cards but realized that customers do not understand why a fee is imposed when other credit card fees for other services are embedded in the market price rather than as an added fee. The cost to Company currently varies by payment method therefore this approach is now more consistent across all customers. The approach still aligns with cost recovery as the credit card customers are still paying $1.00 toward the transaction.

This proposal will create a slight subsidy for customers paying by credit card even though such customers pay a minimal fee. The Company will continue to solicit vendors that will commit to charging a significantly lower fee that will result in less subsidy.

g. Please refer to 5.1(f) above.

h. Please refer to 5.1(f) above.

i. Yes, the depository bank assesses a fee for each withdrawal transaction.

j No, the Company does not.

RESPONDENT:

Brian Bub / Rigo Ramirez

WITNESS:

Denise Smith

RUCO 5.2

Long-Term Incentive Compensation – Please answer the following questions as they relate to long-term incentive compensation:

a. To clarify the Company is seeking long-term incentive compensation of $1,349,782 in the test year and $1,049,924 as a pro forma adjustment for a total of $2,399,706 in long-term incentive expense in this case. If no please explain.

b. Why did the Company not request long-term incentive compensation in its last rate case?

c. Has the Company in prior rate cases asked for long-term incentive compensation? If so, please provide the docket number, along with the Commission decision relating to the Company's request.

d. Why is the Company using a two year average as opposed to a three year average?

e. What Company executives or officers are eligible for the program?

f. List the names of the executives or officers in d. above along with the total long-term incentive compensation provided to them by fiscal year for the test year and three prior years. The test year and prior year amount should reconcile to your pro forma adjustment.

g. Provide a sub account that breaks-out the long-term compensation amounts between salary and payroll taxes for the years noted in f., the test year and prior year amount should reconcile to your pro forma adjustment.

h. From the Company's pro-forma adjustment $180,098 has been capitalized. Please explain to what accounts this amount was allocated to and how this amount was allocated

i. Was any long-term incentive compensation between 7/1/14 through 12/31/14 capitalized? If so, please provide the amount and explain to what accounts this amount was allocated to and how this amount was allocated.

j. Please explain the Fortis Merger long-term incentive compensation expense offset to the Company's pro-forma adjustment in the amount of $2,534,690, and how it was calculated.

k. Please provide a copy of any and all long-term incentive compensation program document(s), and explain how the performance units and restricted stock units relate to the performance goals, if not already provided.

l. Please provide a copy of the Company's benchmarking study.

m. What is the capitalization percentage for the test year?

RESPONSE: **April 4, 2016**

a. No. While responding to data request AECC 5.1, the Company discovered that the amount listed as Fortis Merger LTI Compensation expense was incorrect. As a result the Pro Forma adjustment was updated accordingly. The Company is seeking long-term incentive compensation of $491,910 in the test year and $1,191,919 as a pro forma adjustment for a total of $1,683,829 in long-term incentive expense in this case

b. Because of the size of the revenue request in the last rate case, the Company decided to not request long-term incentive compensation in this last rate case, but reserved the right to request it in this case.

c. Not in the last two rate cases.

d. The Company used the same two year methodology as it did for the payroll adjustment.

e./f. TEP is in the process of gathering this information and will provide it as soon as possible.

g. The Long-Term Incentive Compensation Pro Forma Adjustment does not include payroll taxes.

h. The $180,098 capitalized amount was allocated to FERC 107 via the A&G Allocation.

i. No long-term incentive compensation between 7/1/14 through 12/31/14 was capitalized.

j. The Fortis Merger triggered the payout of all outstanding long-term incentive awards resulting in the accelerated recognition of compensation expense. Compensation expense on these annual awards is typically recognized ratably over a three-year term. In order to normalize the pro forma adjustment, the amount related to the accelerated recognition of compensation expense as a result of the Fortis Merger was deducted. This amount was calculated as follows:

Total Estimated Additional Comp Expense in 2014	$2,680,890
Multiplied by: TEP Mass. Allocation Percentage	x 80.46%
	2,157,044
Add: Payroll Taxes on LTI Payouts	377,646
	$2,534,690

The Payroll Taxes on LTI Payouts amount listed above should not have been included in the Long-Term Incentive Compensation Pro Forma Adjustment. The pro forma adjustment was subsequently updated in a recent data request as referred to in RUCO 5.2a above.

k. Please see the following attached files:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

File Name	Bates Numbers
RUCO 5.2k - 2012 LTI Term Sheet-Confidential.pdf	TEP\021453-021455
RUCO 5.2k - 2013 LTI Term Sheet-Confidential.pdf	TEP\021456-021459
RUCO 5.2k - 2014 LTI Term Sheet-Confidential.pdf	TEP\021460-021463
RUCO 5.2k - 2015 LTI Term Sheet-Confidential.pdf	TEP\021464-021467

l. TEP is in the process of gathering this information and will provide it as soon as possible.

m. The capitalization percentage used in the Long-Term Incentive Compensation Pro Forma Adjustment for the test year was 24.8% for the period 7/1/14 through 12/31/14 and 26.8% for the period 1/1/15 through 6/30/15.

RESPONDENT:

Georgia Hale/ David Lewis/ Steve Bracamonte

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: April 14, 2016

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

e-f, l. Please see RUCO 5.2 (e f & l)-Confidential.pdf, Bates Nos. TEP\021565-021566, for the confidential responses to subparts e, f, and l.

RESPONDENT:

Georgia Hale (e. and f.) / Gabrielle Camacho (l)

WITNESS:

Frank Marino

STF 7.14

Severance Pay:

Reference UDR 1.043.

a. Please explain who was separated and why severance pay was paid.

b. What is the amount of severance the Company is requesting to recover in this rate case?

c. If the Company is seeking recovery, please explain why this is a recurring transaction.

RESPONSE:

a. The severance was paid in the ordinary course of business. Individual severance agreements contain confidentiality agreements that would preclude us from providing names of such employees and the details of the circumstances resulting in the severance payment without their consent. Although we cannot identify each employee individually, the severance payments are generally made to employees at the middle management or professional level or higher, and is consistent with requests made in prior rate cases.

b. As set forth in UDR 1.043 the amount the company is requesting to recover in this rate case is severance pay of $365,688 ($111,835 capitalized and $253,853 O&M). $223,853 of O&M was recorded in FERC Account 920 and $30,000 in FERC Account 580.

c. In the ordinary course of business there are situations which result in severance paid to particular employees. This occurs in any given year, therefore the Company does not deem this to be an extraordinary expense.

RESPONDENT:

Gabrielle Camacho

WITNESS:

Frank Marino

CONFIDENTIAL EXHIBIT KCH-19